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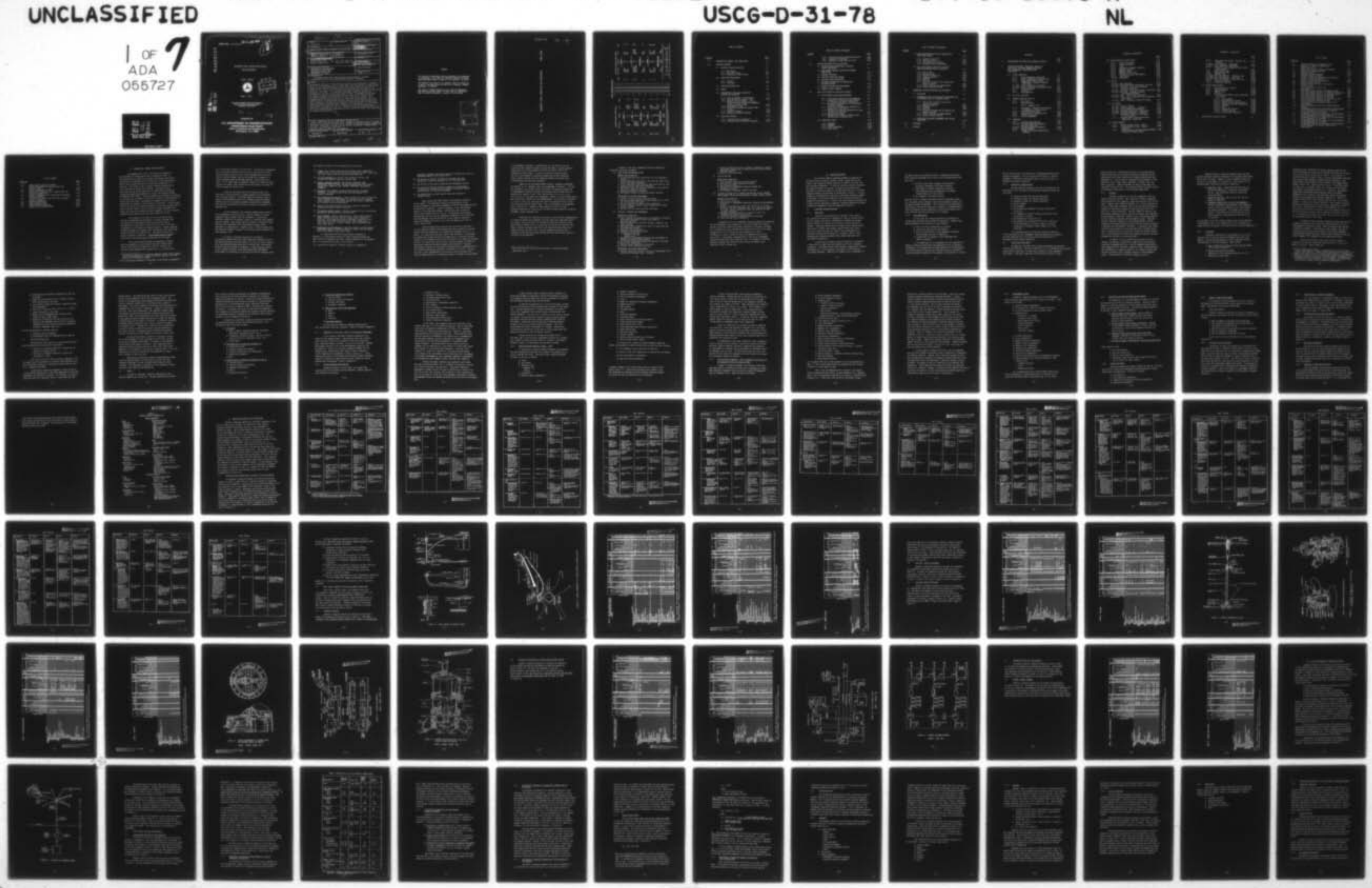

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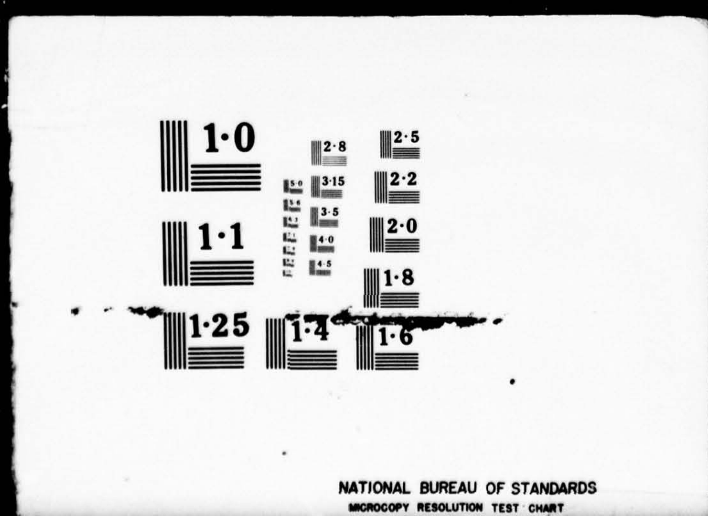

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DEEPWATER PORT INSPECTION METHODS AND PROCEDURES

FINAL REPORT

MARCH 1978

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U.S. DEPARTMENT OF TRANSPORTATION
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16. Abstract

The Deepwater Ports Act of 1974 gives the Secretary of the Department of Transportation and, by delegation, the U.S. Coast Guard, specific authority to regulate the design, construction and operation of Deep Water Ports (DWPs) off the coast of the United States. Some of the regulations deal with safety and prevention of oil pollution. This study is one of several providing information for future regulations dealing with pollution. It identifies and assesses inspection methods and procedures for the Oil Transfer System (OTS) of DWPs. Recommendations are made for inspection methods and procedures that would provide an effective means of minimizing accidental oil spills from the OTS of DWPs in U.S. waters. The recommendations were based primarily on a cost-effectiveness analysis for both commonly used and technologically advanced inspection methods and procedures that were considered to provide the best available technology for DWPs in U.S. waters. Inspection methods considered apply primarily to the components of the OTS, onsite, during normal operations and also to components of other systems whose failure could affect the integrity of the OTS. Failure of components and subsystems of the OTS, which contributed most significantly to the risk of oil spills, were identified in a system safety analysis.

17. Key Words
Deepwater ports, oil transfer system, single point mooring, SALM, CALM, pipelines, hose strings, oil pollution, oil spills, inspection, incipient failure detection, leak detection, fault tree analysis, FMEA, risk analysis, risk reduction.

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METRIC CONVERSION FACTORS

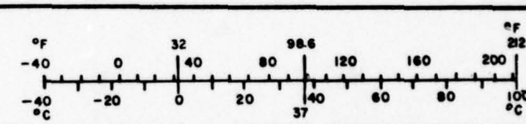
Approximate Conversions to Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
in	inches	*2.5	centimeters	cm
ft	feet	30	centimeters	cm
yd	yards	0.9	meters	m
mi	miles	1.6	kilometers	km
		AREA		
in^2	square inches	6.5	square centimeters	cm^2
ft^2	square feet	0.09	square meters	m^2
yd^2	square yards	0.8	square meters	m^2
mi^2	square miles	2.6	square kilometers	km^2
	acres	0.4	hectares	ha
		MASS (weight)		
oz	ounces	28	grams	g
lb	pounds	0.45	kilograms	kg
	short tons (2000 lb)	0.9	tonnes	t
		VOLUME		
tsp	teaspoons	5	milliliters	ml
Tbsp	tablespoons	15	milliliters	ml
fl oz	fluid ounces	30	milliliters	ml
c	cups	0.24	liters	l
pt	pints	0.47	liters	l
qt	quarts	0.95	liters	l
gal	gallons	3.8	liters	l
ft^3	cubic feet	0.03	cubic meters	m^3
yd^3	cubic yards	0.76	cubic meters	m^3
		TEMPERATURE (exact)		
°F	Fahrenheit temperature	5/9 (after subtracting 32)	Celsius temperature	°C

*1 in ≡ 2.54 (exactly). For other exact conversions and more detailed tables, see NBS Misc. Publ. 286, *Units of Weights and Measures*, Price $2.25, SD Catalog No. C13.10:286.

Approximate Conversions from Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
mm	millimeters	0.04	inches	in
cm	centimeters	0.4	inches	in
m	meters	3.3	feet	ft
m	meters	1.1	yards	yd
km	kilometers	0.6	miles	mi
		AREA		
cm^2	square centimeters	0.16	square inches	in^2
m^2	square meters	1.2	square yards	yd^2
km^2	square kilometers	0.4	square miles	mi^2
ha	hectares (10,000 m^2)	2.5	acres	
		MASS (weight)		
g	grams	0.035	ounces	oz
kg	kilograms	2.2	pounds	lb
t	tonnes (1000 kg)	1.1	short tons	
		VOLUME		
ml	milliliters	0.03	fluid ounces	fl oz
l	liters	2.1	pints	pt
l	liters	1.06	quarts	qt
l	liters	0.26	gallons	gal
m^3	cubic meters	35	cubic feet	ft^3
m^3	cubic meters	1.3	cubic yards	yd^3
		TEMPERATURE (exact)		
°C	Celsius temperature	9/5 (then add 32)	Fahrenheit temperature	°F



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1.0 INTRODUCTION, SUMMARY AND CONCLUSIONS

The Deepwater Port Act of 1974 gives the Secretary of the Department of Transportation and, by delegation, the U. S. Coast Guard specific authority to regulate the design, construction and operation of deepwater ports off the coast of the United States. Some of these regulations deal with safety and prevention of oil pollution. This study is one of several providing information for future regulations dealing with pollution. More specifically, this study has the overall objectives of identifying and assessing inspection methods and procedures for the OTS (Oil Transfer System) of deepwater ports (DWPs). Inspection methods and procedures are defined in this study as the detection of defects* in materials and components of the OTS such that repair, replacement or shutdown of the OTS can be accomplished to prevent or limit ultimate oil pollution. The envisioned results will provide cost-effective means of minimizing accidents and oil spills from this system. Other concurrent programs complement this study; they deal with tankships and their movements, oil spill clean-up equipment and procedures, and the control system for the OTS.

The strategy of the study was first to identify those failures of components and subsystems of the OTS, together with the subsystems of associated structures and controls, which contribute most significantly to the risk of oil spills and which are amenable to risk reduction through inspection. Second, candidate inspection methods and procedures were selected and then ranked based on their potential for reducing risk. The results of the first stage are present in Reference 1, System Safety Analysis Report.** The results of the second stage are described in this report.

This study included methods and procedures to inspect both the components of the OTS itself and other elements whose failure could affect the integrity of the OTS. Clearly, the failure of some component which contains oil (e.g., piping, hose,

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* Includes both inspection for internal component defects before leakage occurs and inspection for a defect that may be causing a tiny leak but not in oil pollution incident.

** For convenience, Reference 1 is included in this report as Appendix C.

etc.) could result directly in an oil spill. The failure of components, such as the mooring hawsers and structure of the pumping platform, also could lead to the failure of an OTS component and an oil spill. Finally, various mistakes, such as the wrong valve alignment or a faulty connection made by the human operators, could cause an oil spill. All of these items are potential subjects of inspections whose purpose is to detect faulty conditions and to prevent or at least to limit the extent of spills of oil.

Primarily, the study deals with inspections which are applicable to the OTS during its steady operation as distinguished from a startup condition. The steady operation period was used to assess the effectiveness and cost of candidate inspection methods. However, most of the inspection methods considered and recommended also could be used effectively during the startup of operations of a deepwater port.

In this connection, the inspection methods apply primarily to the components of the OTS onsite. Specific methods to inspect components before assembly were not considered. In particular, inspection methods for the quality control of individual hose segments were not studied. These methods were the subject of a parallel study (Reference 48) conducted by the Transportation Systems Center, Department of Transportation. However, again it should be noted that the inspection methods considered in this study could be effective for these purposes, also.

All types of inspection methods were considered. The methods included those which might reduce the frequency of spills and those which might limit the volume of oil lost if a spill occurred. Also, the methods included those used in 1970 and 1971, the baseline period for the safety study of Reference 1, state-of-the-art methods in 1977, methods currently in the development state and methods which appear to be feasible but are yet to be tried for deepwater ports.

The inspection methods can be categorized into nine groups.

(1) Visual: from a launch, deck of ship, aircraft, diver, submersible platform, buoy or land, and with optical borehole (internal inspection), low-light TV monitor and oil-sensitive tape detection.

(2) Oil Spill Detectors: on launch, ship, platform, aircraft, SPM (Single Point Mooring) buoy and a special buoy.

(3) Dynamic Insertions Into OTS: dye tracing, inspection pigs, hydrostatic (pressure drop), reflected pressure wave (from cracks), vacuum (with inspection pig), external hydrostatic and acoustic resonance

(4) Corrosion: flow sampling, corrosion meter (electric potential, continuity or corrosion monitoring), holiday detector and cathodic protection

(5) NDT (Non-Destructive Testing): passive ultrasonics, active ultrasonics, x-ray, radioactive isotope, gamma ray, magnetic particle, magnetic rubber, magnetic foil, ultrasonic imaging, eddy current, penetrants, bolt tightness and size measurements

(6) Survey: sonar (pipeline bare surface and overburden inspection), surveying (component location) and scour

(7) Oil Transfer Control System: pressure, volumetric flow, flow velocity, mathematical modeling and leak pressure wave

(8) Special Methods: passive acoustic array - leaks, passive acoustic array - acoustic emission, passive acoustic array - machinery vibration, strain gauge load sensor, continuous thermistor, laser detection, shroud with EMP pulsed coaxial cable, double wall pipe, double wall hose, external loading, seal leak detector and liquid level sensor

(9) Manufacturer and Miscellaneous: inspection schedule and maintenance, operational checks, control room monitors, alarms, shut-off, hydrocarbon probe magnetic chip and oil odor

In conjunction with the failure analysis presented in Reference 1, a preliminary selection of these inspection methods was made for each OTS component and other relevant components of the deepwater port. This selection was based on five criteria:

(1) The ability to detect an incipient failure of a component or

subsystem, subsystem, and thereby provide a criterion for repair or replacement before a spill should occur;

(2) The ability to identify the defective component and, when appropriate, locate the component (e.g., a long pipeline);

(3) The ability to give easily understood and unambiguous results;

(4) The ease with which the inspection method can be implemented, including cost, complexity of use, number of personnel required and reliability in a marine environment;

(5) The adaptability to a wide range of types and locations of deepwater ports

the

These criteria and other factors are discussed in Section 2 of this report. The preliminary selection and application of the inspection methods to the several components of the OTS and deepwater ports are described in Section 3. Section 4 presents a cost-effectiveness analysis of the inspection methods. Effectiveness was estimated in terms of the reduced risk of oil spills. The estimates were based on the potential for oil spills, as developed in Reference 1 for a 1970-1971 baseline deepwater port, and the ability of the inspection method to reduce the frequency of a spill or to limit the amount of oil lost if a spill should occur.

The cost-effectiveness analysis was carried out in Section 4 for the inspection methods and procedures that were considered to provide the best available technology for a hypothetical deepwater port in U. S. waters. All significant costs were used in the evaluation. Effectiveness was measured by considering both the probability of a pollution incident caused by an OTS component failure and the probability of detecting incipient failure. All significant factors such as inspection method, reliability, operational readiness and design adequacy were considered. The cost-effectiveness analysis was the primary consideration for recommendations of the inspection methods and procedures in Sections 5.2 and 5.3. This was also used in the recommendations of alternate or back-up methods that might be needed because of circumstances caused, for example, by operational

or environmental conditions. Consideration also was given to the use of more than one inspection method in situations where a single inspection method would not provide adequate effective inspection, such as the inspection of hose strings. In order to effectively minimize costs, the use of both sequential inspection methods that provide increasing level of detail and the use of an inspection method for multiple uses to help defray costs were also evaluated.

Based on this cost-effectiveness analysis, inspection procedures and methods for U.S. deepwater ports are recommended in Section 5. For many OTS components, such as hose strings, pipelines and mooring systems, new or developmental inspection methods and procedures are available which can substantially reduce oil spill risks (see Sections 4.4.1, 4.4.2, 4.4.4, 4.4.6 and 4.4.7), and these are recommended. However, this cost-effectiveness was not the only criterion for the recommendation. As discussed in Reference 1, a low oil spill risk associated with some OTS components arises in part from inspection methods commonly used. Thus, these methods are recommended also in Section 5.2. Examples of these methods are the use of well-developed techniques for inspections of offshore platform supports, navigation equipment, piping, machinery, etc.

Minimizing the frequency and volume of spills requires implementation of inspection methods and procedures that may necessitate some added costs.* For example, using a mooring line load monitor which only sounds an alarm when excessive loading occurs is a good low cost approach to reducing risks. However, adding continuous monitoring of the loads and monitoring on the pumping platform, possibly with a low cost computerized system, and a scheduling of mooring load system calibrations would provide more effective incipient failure detection.

* These costs are very low considering the cost of the DWP and normal operational costs.

A summary of the main recommended inspection methods and procedures include the following.

(1) HOSE STRING AND MOORING SYSTEM

Methods and current use

- Visual inspections from launch with oil spill detectors--periodic
- Visual inspections from deck of ship with low-light TV and ultraviolet light--continuous
- Visual inspections from launch or small boat with oil spill detectors during offloading--continuous
- Hydrostatic tests, dye tracing inspections, and diver NDT and visual inspection--periodic
- Mooring load monitor--continuous
- Replacement schedule for hoses and hawser--periodic

New methods for further development

- Acoustic array for hose string--continuous
- OTS control system monitoring (flow, pressure, etc.) from ship to platform--continuous
- Oil spill detectors on deck of ship--continuous
- Optical borehole (internal visual inspection of the hose string)--periodic
- Acoustic array for mooring system--continuous

(2) PIPELINE - UNDERSEA AND UNDERGROUND

Methods and current use

- Sonar (sidescan and penetrating) for inspection of pipeline bare surface and depth of burial using towfish technique--periodic
- Mapping inspections of pipeline location, condition and scour--periodic
- Hydrocarbon probe inspection for small oil leak using tow-fish technique--periodic
- Hydrostatic tests--periodic
- Corrosion flow sampling--periodic
- Inspection pig--periodic
    - Magnetic flux type
    - Kaliper type
- Manufacturer's recommended inspection and maintenance of cathodic protection system--periodic
- OTS control system with mathematical modeling--continuous
- Daily visual inspections
- Periodic visual inspection from aircraft
- Periodic visual inspection by divers

New Methods for further development

- Pipeline inspection pig with low-light TV (development of TV transmission technique only) -- periodic

- Pipeline inspection pig with ultrasonic 3-dimentional imaging (development applies only for modification for use on 54-inch pipeline)--periodic
- Acoustic array--continuous

(3) SALM OR CALM SPM

Methods and current use

- Visual and NDT inspections on buoy--periodic
- Diver NDT and visual inspections--periodic
- Dye tracing--periodic
- Manufacturer's recommended inspection methods and procedures--periodic
- OTS component replacement schedule--periodic

(4) OFFSHORE PLATFORM AND THE PUMPING AND METERING SYSTEM, ONSHORE ABOVE-GROUND PIPELINE AND APPURTENANCES, ONSHORE STORAGE TERMINAL

Methods and current use

- Daily visual inspection
- Manufacturer's recommended inspection schedules and maintenance--periodic
- Control room monitoring, alarm, and shut-off of all valves, machinery and other equipment that, if not operating properly or in the incorrect operational mode, can cause an oil spill *incident--continuous*
- Redundant equipment available to replace critical OTS components that potentially can fail
- Oil spill detectors on pumping platform--continuous
- Yearly NDT and visual inspections

Implementation of the recommended inspection methods and procedures and the development of new methods will insure the integrity of the oil transfer system and minimize the number and extent of pollution incidents. It is estimated that these methods would reduce the oil spill risk (annual average barrels of oil spilled) and the frequency of oil spill incidents by a factor of about 10 relative to deepwater ports of the early 1970's. Furthermore, implementation of some of the recommended inspection methods may reduce operating costs, for example, by reducing downtime, extending the life of the hose strings and hawsers, and reducing oil spill cleanup costs.

2.0 INSPECTION METHODS

This section compiles inspection methods for detection of incipient failure in the oil transfer system. Guidelines are provided so that inspection method selection is based on utilizing "the best available technology." In order to provide an overall perspective of inspection methods for the OTS, incipient failure detection is discussed in the first subsection, and the types and uses of incipient inspection methods are described in Subsections 2.2 and 2.3. A survey carried out to determine all potentially applicable inspection methods is described in the fourth subsection, and the methods selected are discussed in Subsection 2.5. Finally, the sixth subsection provides the criteria used for selection of potential inspection methods that appear suitable for components of the OTS subsystem in Section 3.

2.1 INCIPIENT FAILURE DETECTION

2.1.1 Definition

Incipient failure detection is defined in this study as the inspection of materials or components of the oil transfer system in such a manner that repair, replacement or shutdown can be made before a defect can cause failure and result in an oil pollution incident. Inspection methods which can detect either defects before leaks occur or defects that produce insignificantly small leaks, such as oil drips from seals or flanges, are considered here as providing incipient failure detection. Generally, defects can be detected using inspection methods during normal operational and environmental conditions.

A defect may be present but may be found only by applying a stress that is higher than what normally exists for a component or material. The higher stress (high pressures, temperatures, bending, stretching, etc.) can be applied, for example, in proof-testing at elevated pressures. Generally with higher stress, enhancement of

the defect occurs, and incipient failure is detected by monitoring (with inspection equipment) one or more of the following events that may occur:

- Periodic stress waves (commonly called acoustic emissions) generated at the defect location;
- Continuous or sporadic characteristic acoustic leak signatures that are generated at the defect location when an oil leak occurs;
- Oil leakage at the defect location.

When the stress is removed, the defect typically diminishes almost to its original state, leakage or stress wave generation ceases, and the defect becomes undetectable. Thus incipient failure detection is understood to include also detection of material or component defects that are enhanced, during inspection, by controlled elevated stress test conditions and which may result in oil leakage.

2.1.2 Main Application

In this study the inspection methods and procedures developed apply primarily during normal OTS operations. However, they may be applicable also during any of the following:

- Prior to initial installation of the OTS;
- Initial OTS installation and checkout;
- Prior to installation of a new component or material which replaces one that is defective;
- Installation and checkout of the replacement component or material.

It is assumed that all OTS components will be inspected for defects, tested and qualified by the manufacturer prior to delivery. Furthermore, it is assumed that the owner/operator will be responsible for providing both the testing and inspections that will satisfy all existing government regulations (for example, see References 2, 3 and 4)

and for the carrying out of manufacturer recommended maintenance and inspection procedures. This will apply for the receipt of the OTS component, installation, installation checks, and during repair, re placement and onshore inspections.

2.1.3 Conditions of Applications

The main operating conditions that may be required for the application of the incipient-failure-detection inspection methods are as follows:

- Startup of normal OTS transfer operations;
- Continuous normal OTS transfer operations;
- Shutdown of normal OTS transfer operation;
- OTS on standby;
- OTS shutdown;
- OTS shutdown and components isolated from the rest of the OTS;
- OTS component or material removed and placed on land, on platform or in boat;
- OTS shutdown but filled with oil;
- OTS shutdown but sections of OTS filled or partially filled with gases or liquids at normal or stressed (pressurized, stretched, flexed, heated, etc.) test conditions.

It is expected that any of the above operating conditions will be available for the recommended inspection methods and procedures and that inspections will be carried out while observing all U.S. government required safety regulations.

2.2 INSPECTION METHOD MODES

Two modes for incipient failure inspection methods are possible, periodic and continuous. Periodic inspections, (e.g., see Reference 5) have been widely used for many years in almost every industry for most components and systems. Continuous inspections also have been available for many

years but only on a limited basis and only for a few applications. However within the last five years continuous inspections have become widely used in many industries for numerous applications (see References 6, 7 and 8), such as incipient failure detection in ship machinery, valves, tanks, pumps, compressors, bridges, dams and other structures. Inspection methods for each of these modes are identified in Section 2.5.6. The inspection modes as applied to DWP's are discussed in more detail in the following subsections.

2.2.1 Periodic

Presently inspections of the OTS of deepwater ports are almost exclusively periodic. Most inspection intervals, depending upon the particular OTS component, range from each ship visit to five years. However, some inspection methods, e.g., visual inspection of critical, above-water components such as the hose string and mooring system, are carried out a number of times during each ship visit while oil is being transferred. Periodic inspection intervals vary considerably depending primarily upon the OTS design, age, operating and environmental conditions, location, costs, and pressures applied by local regulatory agencies and environmental groups. Optimized periodic inspection schedules for well-maintained DWP's include inspection and schedule adjustments that take into account variations in operating and environmental conditions. In addition, many inspections must be performed on a non-predictable basis following events such as a major storm or collision by a vessel with the OTS installation. Such eventualities require that inspection personnel and most equipment be available on a continuous basis.

In general, it can be stated that the extent to which operators use periodic inspections or comply with current periodic inspection recommendations (e.g., from OTS component manufacturers, other deepwater ports, published inspection guides, inspection equipment manufacturers, regulatory agencies, etc.) depends largely upon pressures exerted by local regulatory agencies and environmental groups. These pressures vary widely throughout the world.

Optimized periodic inspection schedules using the "best available periodic inspection technology" will decrease significantly OTS oil spill incidents. However, critical component failures resulting in a large number of oil spills will occur because of the following major limitations of periodic inspections:

- Inspection times. Inspections typically cannot be carried out adequately in nighttime, rough weather and fog. Some inspections cannot be carried out during offloading.
- Inspection intervals. High cost may limit the frequency of inspections.
- Inadequate inspection of critical OTS components. Periodic inspections and procedures do not adequately inspect critical OTS components such as hose strings and undersea pipelines. For example, many internal defects in hoses which can cause failure can not be found by periodic inspections while the hose string is installed.

A large number of OTS oil leakage incidents occur during nighttime, rough weather or fog. Also, significant oil spill incidents are caused primarily by defects in the hose string or pipeline (Reference 1).

2.2.2 Continuous

Continuous inspections for the prevention of oil spills generally are not used for the OTS at deepwater port facilities. However, a few continuous methods are used at some DWP's either intermittently or for other purposes. These include:

- Visual inspection of the hose string, mooring system, SPM and ship connections;
- Mooring load monitoring systems;
  Monitoring of flow, discharge pressure, etc., for
- Detection of gross leaks.

Continuous visual inspections of the hose string and mooring line during offloading are carried out at some DWP facilities and are sometimes done by patrolling the area by launch. This procedure is not very effective at night, in fog or during rough weather conditions that are not severe enough to prohibit transfer operations. This method detects some incipient failures because visual damage (hoses, hawsers, chains, etc.) often precedes a failure. In addition, small oil leaks (e.g., at flanges, seals, etc.) often can be seen before they become a catastrophic failure (i.e., a rupture). Experimental systems that continuously monitor mooring loads at the hawser (Reference 9) are in use at a few facilities; mooring load monitor systems are also commercially available (Appendix A). During oil transfer, monitoring of flow, discharge pressure, etc., by a control system,* is a type of continuous inspection. Such systems can detect medium and large leaks of oil and shut the OTS down before a major oil spill occurs. Monitoring** by remote sensing methods, such as surveillance by satellite or aircraft is not cost effective and do not provide the type of incipient failure detection as defined in Section 2.1.1; they detect only major spills after they occur and, hence, are not considered further in this study.

A number of other continuous inspection methods (Section 2.5) potentially applicable for the OTS are state-of-the-art or are in a developmental or feasibility stage. Many of these have been applied successfully elsewhere. A particularly useful method is the use of a passive acoustic array which, because of the acoustic phenomena associated with defects and leaks, detects both incipient failures and actual leakage of OTS components such as pipelines and hoses.

Continuous inspections (non-visual) provide a number of advantages over periodic inspections, particularly for critical components of the OTS. Some of these are:

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* A study of DWP control systems is currently being carried out under contract DOT-CG-64503-A. Control systems details are not included in the scope of this report but are discussed briefly because of completeness.

** Detection of major oil spills in an on-going program by the United States Coast Guard and the Environmental Protection Agency. Recommendations for detection of major oil spills is not included in the scope of this report but are discussed briefly because of completeness.

- Continuous day and nighttime inspections in any kind of weather;
- Capability of detecting critical incipient failures almost 100 percent of the time;
- Less subject to human error because inspection systems can be automated;
- Capability of detecting small amounts of oil leakage almost 100 percent of the time;
- Methods can be implemented with existing control systems in new or modern DWP's;
- Capability of detecting incipient failures and oil leakage in OTS components that can not be adequately inspected by periodic inspection methods (underwater pipelines, underwater hoses, etc.).

The main disadvantages or problem areas are:

- Untested in DWP environments;
- Developmental costs for implementation for DWP use.

2.3 INSPECTION METHOD USES

The reduction of the risks of oil spillage and pollution may be accomplished using two general approaches:

- Periodic or continuous inspection to reduce the frequency of accidental spills;
- Continuous or frequent inspection to detect the occurrence of a leak.

The risk of oil spills from the various subsystems of the OTS generally may be ascribed to a relatively high frequency (e.g., the floating hose strings) or a potentially large-volume oil spill (e.g., underwater pipelines).

Inspections to reduce the frequency of leaks and spills include periodic examination of individual components to check their performance and condition for service. The intention is to detect conditions which will eventually lead to a leak before the leak

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actually occurs. The examinations may consist of both visual observation and the performance of one or more instrumented tests. The results of the examinations, when compared with previously established criteria, determine suitability for continued service, repair or replacement. The criteria generally are derived from the manufacturer's recommendations and the user's experience. Examples of such inspections are: the visual examination of the completed, flanged connection between the hose and ship manifold; pressurizing the hose and checking for leaks; routine maintenance of valves, pumps and strainers on the pumping platform; pigging the pipelines to check the condition of welded joints and the extent of corrosion. In addition, continuous inspection methods potentially can be used to reduce the frequency of accidental spills. Examples are: acoustic array to detect hose or pipeline failure by monitoring acoustic emissions generated at the failure location; continuous acoustic monitoring of machinery vibration for bearing or other damage such as broken internal parts.

Continuous monitoring, to detect the occurrence of leaks and initiate shutdown to limit the amount of oil spilled, includes visual and instrumented observations. An example is the comparison of the flows at both ends of a pipeline. Such inspections are an important approach to reduce the risk of spills from "third party" damage (e.g., the damage to a pipeline by a draging anchor). Also such inspections can serve as a backup for the inspections to reduce spill frequency as described above.

Some degree of continuous inspection complementing periodic inspection methods appear to be necessary to provide "the best available technology" in order to significantly reduce oil spill incidents. The technology is available or can be developed, and the life-cycle costs should not be prohibitive.

2.4 SURVEY

A survey of literature, operators, manufacturers and inspection companies was carried out. The main objective was to deter-

mine currently available technologies and component instrumentation that could provide the "best available technology" for inspection methods and procedures for the OTS. The survey included information on inspection methods that were currently available or required minimal modifications, in the developmental stage, laboratory tested and feasibility verified but untested at DWP's, and potentially feasible but untried. In addition, the survey included both the gathering of cost information on inspection methods and procedures and the obtaining of recommended inspection schedules by OTS operators, other offshore operators and OTS component manufacturers.

Information on applicable inspection methods and procedures was obtained from both national and international sources. The following six main areas were surveyed.

(1) Literature:

- Papers, reports, technical journals, periodicals conferences, government reports, etc.;
- Information retrieval services - National Technical Information Service, Engineering Index, etc.;
- Patent search.

(2) User/Operators of Inspection Equipment for:

- Storage facilities;
- Pipelines (above and undersea);
- Offshore installations and transmission;
- Shipbuilding industry;
- DWP.

(3) Manufacturers of Inspection Equipment for Use on:

- Land facilities;
- Pipelines (above and undersea);
- Offshore installations;
- DWP's;
- *Underwater structures*.

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(4) Inspection Companies That Inspect:

- Land facilities;
- Pipelines (above and undersea);
- Offshore facilities;
- Underwater components.

(5) Manufacturers of Main DWP Components:

- SPM's;
- Hawsers;
- Hoses;
- Pipelines.

6) Government Agencies

For the survey of inspection equipment manufacturers, over three hundred firms were contacted. These are listed in Appendix A.

2.5 COMPENDIUM OF APPLICABLE INSPECTION METHODS AND PROCEDURES

In this section, applicable inspection methods will be identified for deepwater ports. Those methods which were initially used up to about 1970 will be identified in the first subsection. Next, inspection methods currently in use will be discussed. Methods which appear feasible or are in the developmental stage will also be identified. Finally all applicable inspection methods will be summarized and categorized by their specific mode of operations. A brief comparison of the methods is given in Section 3.1. A more detailed description of each method and procedure including operation, capability, sensitivity, manufacturer and cost information, and advantages and disadvantages is given in Appendix B.

2.5.1 Existing Methods-1970 Baseline

Inspection methods in use for DWP's up to about 1970 provided very little incipient failure detection. Methods generally used included the following:

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- Periodic visual;
- Hydrostatic (pressure drop);
- Discharge pressure monitoring;
- Flow monitoring;
- Manufacturer's recommended inspections;
- Bolt tightness;
- Active ultrasonics (limited underwater use);
- X-ray (above water);
- Eddy current (above water);
- Penetrants (above water);
- Size measurements (above water);
- Cathodic protection inspection.

In the 1960's, most deepwater ports were installed in geographic areas near a very low population density. Most of these deepwater ports were owned and operated by affiliates of oil companies. The parent oil companies provided operating, inspection and maintenance guidelines to the operating affiliates. These guidelines were based on engineering fundamentals, the manufacturer's recommendations and the parent company's previous experience with deepwater ports. Unfortunately, the engineering fundamentals, as applied to DWPs needed refinement. The manufacturers did not receive sufficient feedback from the operators so it was difficult to refine their equipment without full scale operational experience. There was little incentive for a particular operator to follow the furnished guidelines because of the low monetary value of petroleum lost, the absence of stringent requirements of local regulatory agencies or governments, and the absence of environmental concern from the local community.

Without the proper incentive, many terminals, which would have been considered marginal by U.S. standards of operation, resorted to a "seat-of-the-pants" type operation. The primary inspection-maintenance strategy used by this type of terminal was to watch for an oil slick on the sea's surface, then to perform a visual inspection by diver or by launch to locate the failed component, and finally to replace the component during fair weather and after having received the replacement part.

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At many terminals, when a problem occurred, operators repaired the equipment as necessary to permit the operation to continue. The permanent repair was made after the spare equipment was received and the weather conditions were fine and stable.

In addition to watching for oil slicks at the sea's surface, the well-maintained facilities provided some incipient failure inspection. The main methods were to inspect periodically and visually critical OTS components such as hose strings, mooring system and subsea components. This was done by looking for gross external damage, oil leakage and checking bolt tightness primarily on hose flanges. Hydrostatic pressure tests were usually conducted after storms or bad weather. Continuous visual monitoring of discharge pressure, volume and flow was carried out during offloading. This monitoring could only detect catastrophic oil leakage. Conventional, non-destructive testing was carried out on critical above water components periodically at very infrequent intervals.

The most effective oil prevention procedure used at most DWP's was to carry out hose replacement according to a schedule that, hopefully, would preclude a major oil incident. Replacement schedules, however, varied greatly from one DWP to another.

2.5.2 State-of-the-Art Methods at DWP's - 1977

In recent years, existing inspection methods and procedures have been substantially improved, and a number of new methods are in use at a few DWP facilities. These more recent inspection methods currently in use are as follows:

- Visual ;
- Dye tracing ;
- Inspection pigs
  - Magnetic flux
  - Caliper ;
- Hydrostatic ;
- Corrosion meter (underwater) ;

- Cathodic inspection;
- Passive ultrasonics (limited use);
- Active ultrasonics (underwater);
- X-ray;
- Gamma ray, Radioactive isotopes (underwater);
- Magnetic particle;
- Eddy current;
- Size measurements;
- Sonar;
- Surveying (mapping);
- Scour monitoring;
- Visual monitoring of discharge pressure;
- Visual monitoring of volume;
- Visual monitoring of flow;
- Strain gage load sensor mooring load monitor;
- Double walled hose;
- Tank level detection ;
- External loading ;
- Passive acoustic monitoring of vibration;
- Control system alarms, shutoff.

The incentive for industry to develop improved inspection methods and procedures at DWP facilities have resulted from the following:

(1) The tremendous rise of the price of crude oil;

(2) Concern by the local communities to preserve the environment;

(3) Local governmental requirements;

(4) Regulatory body requirements.

In general, however, only installations which are located in high amenity areas (i.e., located near populated areas, beaches, etc.) have developed and implemented new and improved inspection methods and procedures that are thorough and used frequently.

All well maintained DWP's have regularly scheduled inspection schedules. Between the time of delivery of the SPM and its first major overhaul, inspections are performed on all the components of the oil transfer system and all the components relative to the integrity and safety of the OTS. These inspections are primarily visual inspections by a diver or by a launch. Their purpose is to detect damage or signs of damage after it has already occurred. The operators schedule the inspections frequently enough (in many cases) to locate signs of a failure before the component fails completely with catastrophic results. In addition, the other inspection methods identified previously in this section are used to a very limited extent to supplement these visual inspections.

Few or no inspections for incipient failures of pipelines are carried out, other than hydrostatic testing or in a few cases, pipeline inspection pigging which are performed infrequently at best. There appears to be the mistaken confidence that the underground and undersea pipeline leaks rarely or never occur and hence need few or no inspection for incipient failures.

To compensate for the visual inspection's lack of sophistication to detect a failure before it occurs and limited use of other available inspection methods, operators frequently have scheduled the replacement of equipment and the performance of destructive tests on components such as hoses. The destructive tests are used to determine how much longer the component could have lasted and to adjust the replacement schedule accordingly.

2.5.3 State-of-the-Art Methods - 1977 at Offshore Facilities with OTS Components Similar to Those of DWPs

A number of inspection methods, not previously identified, have been applied to offshore facilities and to underground or underwater pipelines components that are similar to those OTS components used for deepwater ports. These include the following:

- Optical borehole (machinery);
- Oil spill detectors on boat;
- Inspection Pig,
  - TV monitor (short pipelines),
  - Stereo TV (short pipelines),
  - Passive ultrasonics,
  - Eddy current,
  - Location type (pinger, radio frequency, nuclear),
  - Manned NDT (short, large diameter pipelines);
- Reflected pressure wave;
- Flow sampling (coupons, particles, etc.);
- X-ray (underwater);
- Magnetic particle (underwater);
- Magnetic foil (underwater);
- Magnetic tape (underwater);
- Ultrasonic imaging (underwater);
- Eddy current (underwater);
- Sonar (pipeline bare surface or overburden);
- Control system flow monitoring;
- Control system pressure, volume monitoring;
- Passive acoustic array (acoustic emission) - platform structure, tanks, etc.;
- Passive acoustics - leaks;
- Passive acoustics - machinery vibration, bearing noise;
- Seal leak detector;
- Hydrocarbon monitoring.

It is expected that most of these methods can be used immediately at DWP's. A few of these methods should be developed further for more reliable or a wider range of usage.

Only a very few deepwater ports currently in use require offshore pumping platforms similar to those needed for U.S. deepwater ports. This is because most other DWP's are located a relatively short distance (i.e., a few miles) from the SPM to the onshore storage

terminal and a pumping platform is not necessary. Hence only limited inspection method information was obtained from DWP's. Instead, inspection methods and procedures information were obtained from the numerous offshore pumping platforms that are used for drilling at U.S. and foreign locations. Many of these platforms use designs and components that are similar to what is expected to be used for U.S. deepwater port OTS platforms. Offshore platforms currently have a very low oil spill incident probability. This is because of secondary containment systems such as deck curbing for oil spills, building a redundancy in the equipment involved, using state-of-the-art inspection methods for OTS components and platform structure, and rigorously following manufacturer inspection methods and maintenance procedures. When a failure occurs in the equipment, the operation only requires switching to a similar system in parallel with the failed system and making the repair at the earliest convenient opportunity. There is, however, still need for improvement for OTS platforms, primarily in platform structure inspection and, to a larger degree, in inspection and detection of defects in the deck area that may lead to leaks. Complete and thorough inspection of the platform support structure is very costly and time consuming. Inspection methods that can be carried out quickly and that can cover large areas are more cost-effective and highly desirable.

A large number of offshore facilities carry out comprehensive corrosion inspection programs and sonar inspections of underground and undersea pipelines. However, these inspection programs are somewhat limited both by frequency of inspections (caused primarily by cost considerations) and by the technology of inspection methods currently available. An example is the use of pipeline pig with magnetic flux inspections. These inspections are costly and results are sometimes difficult to interpret. However, a pipeline pig with magnetic flux that is used with a TV camera (if a long line system was available) would provide excellent data and require minimal interpretation.

2.5.4 Developmental Stage

A number of inspection methods are in the developmental state or require some modifications for reliable use at DWP's. These include the following:

- Optical borehole (underwater);
- TV scanning (low light) with onshore monitoring;
- Oil spill detectors on buoy, platform, ship;
- Inspection pig,
  - TV monitor in vacuum,
  - TV monitor (long lines),
  - Stereo camera (long lines),
  - Infrared scanning,
  - Active ultrasonic,
  - Eddy current,
  - Ultrasonic imaging;
- External hydrostatic;
- X-ray (underwater);
- Magnetic particle (underwater);
- Magnetic rubber (underwater);
- Magnetic foil (underwater);
- Magnetic tape (underwater);
- Ultrasonic imaging (underwater);
- Eddy current (underwater);
- Control system monitoring using mathematical modeling;
- Passive acoustic array (acoustic emission or leak detection) for,
  - Platform structure,
  - Tanks,
  - Double walled pipe.

It is expected that most of these methods either could be used immediately or become operational in a few years and in sufficient time before DWP's become operational in U.S. waters.

2.5.5 Feasibility Verified but Requires DWP Testing

The feasibility of a few new methods to inspect for incipient failures has been verified by laboratory testing. Testing at DWPs is required to establish capability of these methods under actual operational and environmental conditions. The following methods appear to be the best in their respective categories.

(1) Passive acoustic array (leaks): May be capable of detecting very small leakage primarily from hoses, pipelines and SPM piping, valves and Pipeline End Manifold (PLEM) components.

(2) Passive acoustic array (acoustic emission): Expected to be capable of detecting defects in hoses, pipelines and SPM piping, valves, PLEM components and the platform structure.

(3) Shroud with EMP pulsed coaxial cable (very small leakage): Expected to be especially useful for hose strings, SPM's and undersea pipelines.

(4) Ultrasonic imaging inspection pig (propelled by water flow)

Other methods include:

- Seal leak detector;
- Continuous thermistor;
- Buoy oil spill detectors;
- Flourescent light (to aid visual inspection on deck of ship or launch for night viewing).

2.5.6 Feasibility Stage

Inspection methods which appear feasible for DWP use, but which would require research and development and also substantial testing before actual implementation, include the following:

- Tape detection;
- Laser detection (underwater);
- Inspection pig (radioactive for leak detection);
- Penetrants (underwater).

2.5.7 Summary of Applicable Methods

All applicable inspection methods are listed in Table 2.1. The methods are classified by their use in periodic or continuous modes. Some methods can be used in either mode.

2.6 SELECTION CRITERIA

Potential inspection techniques for specific components of the OTS subsystems (see Section 3.0) were selected using the following criteria:

- Must be capable of incipient failure detection;
- Must identify the component that requires repair or replacement to prevent failure;
- Must give positive results which are easily understood;
- Must be reasonably implemented;
- Must be adaptable to other DWP facilities.

These criteria are described more fully in the following subsections.

2.6.1 Incipient Failure Detection

Inspections to reduce the frequency of an accidental spill must identify failures or incipient failures before a spill can occur. Examples are the identification of a kinked hose or dangerously corroded pipe. By current practice, even at the most conscientiously operated DWP facilities, a defective component is usually identified after it has failed and resulted in a spill. The results are costly in terms of delay while waiting for a spare as well as by the quantity of oil lost and, often, the environmental damage which ensues. If the potential failure of a component can be anticipated early enough by appropriate inspection methods, a repair can be made or a replacement installed at the optimum time in terms of weather and interruption of transfer operations.

2.6.2 Identification of Defective Component

It is not enough for an inspection method to provide the information that leakage exists or even that it is imminent. The component which has failed, or is about to fail, must be readily identified in order to permit repair or replacement in the least possible time. This is necessary for both types of inspections, those to reduce frequency of spill and those to detect leaks.

2.6.3 Positive and Easily Understood Results

An important criterion for selecting an inspection method should be that it requires the least possible amount of interpretation and judgment by the operator. The method should provide results which not only identify the defective component, but which can be evaluated quickly and easily by non-specialized personnel. A permanent, quantitative record which can be used in real time as well as serve as a basis for comparison during subsequent inspections also is desirable in many circumstances. Examples of the latter includes pressure and flow records, records of the extent of corrosion, the length of mooring hawser, etc.

2.6.4 Reasonably Implemented

Even the most efficient inspection method would prove to be self-defeating if its use required unreasonable downtime of the facility. Nor can excessive capital expense for equipment be justified if alternative and less expensive methods will prove adequate. The need to provide easily understood results implies a corollary need to select inspection techniques which can be conducted by relatively unskilled personnel.

2.6.5 Adaptable to Other DWP Facilities

Since environmental and operating conditions will differ to some extent between the several coasts of the United States and even between different sections of the same coast, every effort should be made to adopt inspection methods which are sufficiently flexible to be used under any anticipated conditions. It is conceivable that

a particular facility might operate under extreme conditions which would require the application of more stringent or sophisticated inspection methods, but, in general, the utilization of "tailor-made" procedures should be avoided.

TABLE 2-1

INSPECTION METHODS FOR DEEPWATER PORTS

Periodic Inspections

Visual

- Above water
- Underwater
- Optical borehole
- TV monitor
- Tape detection

Oil Spill Detectors

- Buoy type
- Mounted on launch, ship, buoy, platform, land

Dynamic OTS

- Dye tracing
- Inspection pigs
- Hydrostatic (pressure drop)
- Reflected pressure wave
- Vacuum (with inspection pig)
- External hydrostatic
- Acoustic resonance

Corrosion

- Flow sampling (coupons, particles, etc.)
- Corrosion meter (electric potential, etc.)
- Holiday detector
- Cathodic protection (mfg. schedule)

Manufacturer

- Inspections
- Operational checks

Miscellaneous

- Control room monitoring, alarms shut-off
- Hydrocarbon probe
- Laser holography
- Magnetic chip
- Oil odor

Non-Destructive Testing

- Passive ultrasonics
- Active ultrasonics
- X-ray
- Gamma ray, radioactive isotopes
- Magnetic particle
- Magnetic rubber
- Magnetic foil
- Magnetic tape
- Ultrasonic imaging
- Eddy current
- Penetrants
- Bolt tightness
- Size measurements

Survey

- Sonar (pipeline bare surface or overburden
- Surveying (component location, mapping)
- Scour

Oil Transfer Control System

- Pressure, volume
- Flow
- Mathematical modeling

Special Methods

- Passive acoustic array - leaks
- Passive acoustic array - acoustic emission
- Passive acoustic array - machinery vibration
- Strain-gaged load sensor, mooring load monitor
- Thermistor
- Laser detection underwater or above water
- Shroud with EMP pulsed coaxial cable
- External loading
- Seal leak detector
- Liquid level sensor
- Double walled pipe or hose

Continuous Inspection

Visual

- Above water
- TV monitor

Oil spill detectors

- Buoy type
- Mounted on launch, buoy, platform, land

Miscellaneous

- Control room monitoring, alarms, shut-off
- Magnetic chip

Oil Transfer Control System

- Pressure, volume
- Flow
- Mathematical modeling

Special Methods

- Passive acoustic array - leaks
- Passive acoustic array - acoustic emission
- Passive acoustic array - machinery vibration
- Strain-gaged load sensor, mooring load monitor
- Continuous thermistor
- Laser detection-underwater or above water
- Shroud with EMP pulsed coaxial cable
- Double walled pipe or hose

3.0 INSPECTION METHODS FOR OTS SUBSYSTEMS

Potential inspection methods for individual components of the OTS for a wide variety of DWP's are identified in this section. Inspection methods include those that are in the development or feasibility stage. Some of these methods currently are of little use but improvements may result in effective use because of increased sensitivity, reliability, use of data interpretation, etc. The selection and effectiveness of the methods identified also can vary widely depending, for example, on DWP size and location, number of SPM's, SPM and offshore platform depth, number of offloadings, etc. A description and a comparison of these methods are given in the first subsection. Then a hypothetical OTS is divided into seven major subsystems and described in separate subsections. Since either a Single Anchor Leg Mooring (SALM) or a Cantenary Anchor Leg Mooring (CALM) configuration may be used for the single point mooring subsystems of the OTS, they are treated separately in the fourth and fifth subsections. Each subsystem contains a brief discussion and a summary table which includes the main OTS components and potential inspection methods. Of these methods, those which appear to have the best potential for the hypothetical deepwater port studied in Reference 1, which is a composite of LOOP and SEADOCK, are selected in Section 4 and evaluated further prior to final recommendation in Section 5.1.

3.1 DESCRIPTION AND COMPARISON OF POTENTIAL INSPECTION METHODS

All potential inspection methods are briefly described and compared in Table 3-1 where fifty-six inspection methods are separated into nine basic categories. Because most of the inspection methods can be used potentially for a large number of OTS components, inputs to the table are general in nature. References used on those providing additional useful information for the inspection methods are noted in the table. Manufacturer and other pertinent survey information is given in Appendix A. More detailed information on inspection methods and procedures is given in Appendix B. Inspection method details given in Appendix A such as what specific visual inspections can be carried out (these inspections are quite extensive for some OTS components) will be included in Appendix B. Complete details of the recommended inspections are given in Section 5.1.

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TABLE 3-1 COMPARISON OF INSPECTION METHODS* FOR DEEPWATER PORT OTS

INSPECTION METHOD(m)	DEFECT MEASURED	SENSITIVITY**	ADVANTAGES***	DISADVANTAGES
1.0 VISUAL				
1.1 From Launch (Hose string, mooring system, SPM, etc.)	1. Oil leaks 2. External defects 3. Orientation, alignment, movement problems that can cause failure 4. Mooring system failures at buoy and mooring line	1. Catastrophic failures - early detection 2. Minor above water spills 3. Medium underwater spills 4. Detection of oil leak by odor	1. Provides wide range of visual inspections 2. Simple 3. Good incipient failure detection	1. High cost 2. Cannot be used in bad weather 3. Not adequate in darkness 4. Subject to personnel error 5. Difficulty in discriminating between an oil spill and the oil sheen from boat engines or a few liters of oil leakage at ship (this may cause sheen over a wide area).
1.2(a) On Deck of Ship (Hose string, mooring system, SPM, etc.)	1. Oil leaks 2. Some external defects on tail hose only 3. Orientation, alignment, movement problems that can cause failure 4. Mooring system failures at ship	1. Catastrophic failures - early detection 2. Medium to major spills	1. Simple 2. Good for shipboard connections and tail hose failures 3. Some incipient failure detection	1. Inadequate in bad weather, fog, and in darkness except for ship breakout 2. Subject to personnel error 3. Difficulty in discriminating between minor spills and thin oil sheen on surface of water (oil sheen can occur from a few liters of oil leakage and can cover a wide area) 4. High cost
1.2(b) Man on Deck of Ship at Night with Visual Inspection but Using Ultraviolet Light Source	1. Oil leaks on water	1. Ultraviolet light causes oil to fluoresce and be easily seen.	1. Simple 2. Aids visual inspection 3. Low cost 4. Some incipient failure detection 5. Works well at night	
1.3 Diver or Scuba Diver (10) (Hose string, SPM, Platform, Pipeline, PLEM, etc.)	1. Oil leaks 2. External physical defects 3. Orientation, alignment and movement problems that can cause failure	1. Minor spills 2. Small oil leaks	1. Good incipient failure detection 2. Underwater inspection	1. Medium cost 2. Inspection frequency is limited 3. Cannot be used in fog, darkness, and rough water 4. Subject to personnel error 5. Photographic records and video tape records sometimes unreliable or difficult to interpret
1.4 Submersible-Manned or (10) Remote Controlled (Pipeline, pumping platform support structure)	1. Oil leaks 2. Leaks or defects in underwater pipeline 3. Platform structure damage	1. Medium to major spills	1. Particularly useful if defect or failure is expected based on other inspections or if a major earthquake occurs. 2. Some incipient failure detection 3. Fast inspections over wide area	1. High cost
1.5(a) On SPM Buoy (Hose string, SPM, mooring system, ship connections, etc.)	1. Oil leaks at or near buoy 2. Some external hose string defects 3. Orientation alignment and movement problems that can cause failure 4. Mooring system failures at buoy and along mooring line 5. Hose string leaks or rupture	1. Catastrophic failures-early detection 2. Minor above water spills 3. Medium underwater spill	1. Particularly useful on CALM 2. Simple 3. Provides wide range of visual inspections 4. Provides some useful incipient failure detection in fog or darkness	1. High cost 2. Difficult to implement for SALM SALM buoys 3. Cannot be used in rough weather 4. Subject to personnel error 5. Could be hazardous to personnel
1.5(b) On Pumping Platform (Platform, pipeline)	1. Oil leaks 2. External piping (riser) damage	1. minor to medium spills	1. Simple 2. Some incipient failure detection	1. Difficult to discriminate between thick oil spills and thin oil sheen on surface of water 2. High cost
1.6 Optical Borehole (Flexible viewing probe with light that is inserted into component through flanges for hose string, pipeline, SPM, PLEM, etc.)	1. Internal surface of hose, chamber, pipeline, valve or machinery	1. 360° viewing in all planes	1. Good incipient failure detection 2. Commercially available 3. Low cost 4. Simple 5. Permanent record 6. Inspection of areas of that cannot be inspected other means	1. Requires that inspected area be emptied of oil

NOTES: * See Tables 3-2 through 3-8 and Tables 4-2 through 4-10 for specific OTS component application
(m)Identifies Reference number
** Minor spill <10,000 gal (238 barrels); Medium spill 10,000 to 100,000 gal; Major spill >100,000 gal.
*** Very rough estimate of inspection costs for year for OTS components that would typically be inspected: Low cost 0 - $20K; Medium cost $20K to 200K; High cost >$200K.

95% (44)

TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
1.7(a) TV Monitor on SPM Buoy (Broad coverage of hose string and mooring system-low light TV camera)	1. Oil leaks 2. Orientation, alignment, and movement problems that can cause failure 3. Ship breakout	1. Catastrophic failure-early detection 2. Medium or minor spills	1. Simple 2. Wide area of coverage 3. Operates at light levels inadequate for visual inspection 4. Some incipient failure detection 5. Commercially available	1. Inadequate in fog, bad weather and in darkness 2. Not as effective as continuous visual inspection
1.7(b) TV Monitor on Ship (Broad coverage of hose string and mooring system-low light TV camera)	1. Oil leaks 2. Orientation, alignment and movement problems that can cause failure 1. Ship breakout	1. Catastrophic failure-early detection 2. Medium or minor spills	1. Simple 2. Wide area of coverage 3. Operates at light levels inadequate for visual inspection 4. Some incipient failure detection 5. Commercially available 6. Aids visual inspection on deck of ship	1. Inadequate in fog, bad weather or darkness 2. Not as effective as continuous visual inspection
1.7(c) TV Monitor on Pumping Platform (Broad coverage of platform, pipeline, ship movement, etc. - low light TV camera)	1. Oil leaks	1. Minor spills	1. Simple 2. Wide area of coverage 3. Operates at light levels inadequate for visual inspection 4. Some incipient failure detection 5. Commercially available 6. Low cost 7. Aids visual inspection on pumping platform	1. Inadequate in fog, bad weather or darkness 2. Not as effective as continuous visual inspection
1.8 Tape Detection (11) (Tape wrapped around hose, flange, etc. leaked oil will change color or tape electrical characteristics)	1. Oil leaks	1. Minor spills	1. Simple 2. Good incipient failure detection 3. Can be used for continuous inspection 4. Can be used underwater	1. Not rugged 2. Feasibility/development stage 3. High cost
2.0 OIL SPILL DETECTOR (12),(13),(14) (Continuous Monitoring)				
2.1 On Launch - Infrared Type (Infrared type point sensor. Transmitter projects an infrared light beam to surface of water and reflected infrared light is analyzed by receiver. An alarm is activated when oil is detected.)	1. Oil spills on water	1. Device has been proven in U.S.C.G. tests to detect oil spills in rough water 2. Monitors a small area typically less than a square foot	1. Simple 2. Low cost 3. Good incipient failure detection 4. Reduces dependence on visual inspection 5. Some commercial instruments can discriminate between thick film and on oil sheen. This is difficult to interpret by visual inspection. 6. Some commercial devices are explosion proof certified.	1. Currently not used on launches. However, a few oil terminals in Europe are considering purchase of such devices 2. Alignment may be a problem in very rough weather 3. Monitors a small area typically less than a square foot
2.2 On Deck of Ship-Infrared (Operation same as 2.1 except devices must be battery powered, portable and satisfy explosion proof regulations)	1. Oil spills on water	1. Located at bow of ship 2. Can work at height of about 30 meters	1. Simple 2. Medium cost 3. Works in fog 4. Some incipient failure detections since oil spills from SPM would normally drift to ship 5. Aids visual inspections 6. Useful at night	1. No commercial version exists for use on deck of ship, but maybe available in near future 2. Medium development funding for ship mounted version 3. Device must meet explosion certification 4. Tide can go in one direction and wind in another direction so that detector may not see oil leaks under certain conditions 5. Requires a relatively stable platform for a spot type sensor 6. Sensor must allow for changes in draft of ship

TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
2.3(a) On Platform-Infrared (See operation 2.1)	1. Oil spills on water	1. Many oil companies are currently using these devices at supertanker terminals for oil spill detection; usually installed on piling or on deck	1. Simple 2. Low cost 3. Works in fog 4. Some incipient failure detection 5. Commercially available 6. Aids visual inspection	1. Requires about 4 sensors on platform
2.3(b) On Platform-Fluorescent (Scanning fluorescense type sensor but operation similar to 2.1)	1. Oil leaks in water at night	1. 600 to 1000-foot range	1. Works well at night 2. Medium cost 3. Commercially available 4. Some incipient failure detection 5. Aids visual inspection	1. No daylight operation
2.4(a) On Buoy-Infrared (Infrared type point sensor. Transmitter projects a light beam to surface of water and reflected infrared light is analyzed by a receiver. An alarm is activated when oil detected)	1. Oil spills on water	1. Small area	1. Simple 2. Low cost 3. Some incipient failure detection 4. Particularly useful on CALM buoy at first hose off buoy	1. No commercial version available for use on buoy
2.4(b) On Buoy-Scanning Infrared	1. Oil leaks on water	1. Wide range around buoy	1. Some incipient failure detection 2. May require only one sensor on buoy	1. Feasibility stage only 2. Medium cost 3. Range uncertain at this time 4. Complex
2.5(a) Buoy Type(In Situ) Membrane Type (Device floats near the DWP component and separates oil from water by a permeable membrane. Device senses presence of small quantity of oil through self heated sensor that responds to differences in thermal conductivity between air and oil)	1. Oil leaks on water	1. Range about 1 meter	1. Simple 2. Low cost 3. Some incipient failure detection	1. No commercial version available 2. Would require an array to be very effective 3. Must provide safe, explosion-proof operation under severe environment or external impacts
2.5(b) Buoy Type(In Situ) Ultraviolet (Works on ultraviolet detection principle)	1. Oil leaks on water	1. Range about 1 meter	1. Simple 2. Low cost 3. Some incipient failure detection	1. Does not work well in daytime 2. No commercial version available 3. Usually requires an array of sensors to be very effective 4. Must be explosion proof
2.5(c) Buoy Type(In Situ) Infrared (See operation 2.1)	1. Oil leaks on water	1. Range about 1 meter	1. Simple 2. Low cost 3. Some incipient failure detection	1. No commercial version available 2. Usually requires a variety of sensors to be effective 3. Must be explosion proof
3.0 DYNAMIC INSERTION INTO OTS				
3.1(a) Dye Tracing-Visual[15] (Insertion of dye under pressure into OTS components such as pipelines, hose string etc., and look for dye leaking out of an OTS component)	1. Small leaks	1. Minor Spills	1. Simple 2. Low cost 3. Good incipient failure detection 4. Can be used in darkness 5. Commercially available 6. Useful when residual oil or oil from external sources cause difficulty in detecting leak	1. Slow inspection method 2. Requires out-of-service inspection 3. Should be used only when other visual inspections cannot detect a leak
3.1(b) Dye Tracing-[15] Fluorometer (Insertion of dye under pressure into OTS components such as hose string, pipeline, SPM etc. and monitor leaks with detector)	1. Small leaks	1. Very minor leaks 2. 10^5 leak sensitivity 3. 10 to 100 times more sensitive than visual dye tracing inspection	1. Simple 2. Low cost 3. Good incipient failure detection 4. Not subject to personnel error 5. Commercially available 6. Useful when residual oil or oil from external sources cause difficulty is detecting leaks	1. Slow inspection method 2. Requires out-of-service inspection 3. Should be used only when other visual inspections cannot detect leaks

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TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
3.2.1 Inspection Pigs (11) (Propelled through pipeline by fluid flow)				
3.2.1(a) Magnetic Flux (16) (electromagnetic Changes in wall thickness affects magnetic field. Induced magnetic field and detection accomplished with electromagnets or permanent magnets.)	1. Corrosion 2. Hardspots, mfg. flaws 3. Girth welds, pits 4. Cathodic protection 5. Improper bends of pipeline 6. Gouges 7. Wrinkle brads 8. Hydrogen blisters 9. Bends	1. Severity of corrosion in three ranges- 15-30% of wall 30-50% of wall >50% of wall 2. Approximately 1/8 inch defect 3. Severity of pitting	1. High reliability 2. Locates defects 3. Permanent record 4. Monitors integrity of line 5. Locates potential failures before they become catastrophic 6. Helps evaluate effectiveness of cathodic protection coating 7. Commercially available	1. High cost 2. Difficult to interpret magnetic anomalies 3. Requires human interpretation 4. Electromagnet type cannot determine if defect is inside or outside of pipe 5. Permanent magnet type can get stuck in pipeline and be difficult to remove 6. Anomalies around girth weld difficult to detect 7. Does not detect thin cracks very well
3.2.1(b) Kaliper (17) (Finger mechanism in pig transmits changes in pipe diameters to a charting device in pig housing.)	1. Measures changes in inside pipeline diameter 2. Detects dents, buckles 3. Detects obstructions 4. Changes in wall thickness 5. Flat spots, bends 6. Partially closed valves	1. Abrupt changes in wall thickness of 1/8" or more 2. High degree of accuracy of measuring length of heavy wall pipe	1. Extremely useful in new pipeline construction 2. Medium cost 3. Locates size and location of significant changes in pipeline	1. Much lower sensitivity than magnetic flux inspection pig
3.2.1(c) Active Ultrasonics (Ultrasonically scans pipeline in transverse direction using active ultrasonic scanning tool.)	1. Pipe wall thickness 2. Laminations 3. Inclusions 4. Cracks	1. Indicates dimension of defect	1. Location of defect 2. Permanent record	1. High cost 2. Difficult to interpret 3. Requires human interpretation 4. Not widely used
3.2.1(d) Passive Ultrasonics (18) (An escaping fluid from a pipeline leak emits sounds. Passive ultrasonic detectors, mounted in an oil tight container, detect the leak.)	1. Leak detection through hair cracks or small corrosion holes	1. 3 to 5 gallons per hour leaks	1. Locates leak within a few feet 2. Should work well if a leak detector pig is built and dedicated for a specific pipeline	1. High cost 2. Not commercially in use in the U.S. because of difficulty in applying device to a variety of pipelines 3. Requires some development for reliable results 4. Background noise currently limits leak resolution
3.2.1(e) TV Camera (TV inspection camera with low light TV camera and video tape or TV monitor.)	1. Visually inspects inside of pipeline for cracks, pits, etc.	1. Slightly better than visual inspection 2. 360° viewing	1. Simple 2. Permanent record 3. Medium cost	1. In feasibility stage only because TV signals currently cannot be transmitted without a cable attached to camera. See 3.2.2(a)
3.2.1(f) Nuclear (Nuclear source installed in inspection pig to detect leaking minute radioactive quantities outside the pipe.)	1. Small hole through cracks	1. Sensitivity uncertain	1. Simple	1. Feasibility stage only 2. Radiation safety requirement 3. High signal attenuation from source caused by water 4. High cost
3.2.1(g) Ultrasonic(Holographic) Imaging (19) (3-dimensional view of inside of pipeline wall-includes scanning head, recording module, electronic holographic computer signal processor and power supply. See appendix B for further information.)	1. Defects inside the material 2. Corrosion and or erosion 3. Pits 4. Loss of material on inside or outside of wall 5. Wall thickness	1. Flaw area of about 0.2mm x 0.2mm 2. Instrument can be set to meet any API specification 3. Thickness resolution of about .05mm 4. Provides 3 dimensional image showing length, width, geometry and depth	1. Excellent picture of inside pipe 2. Covers 5 to 10 miles per hour 3. Excellent incipient failure detection 4. Simple interpretation of data	1. High cost* 2. Product not commercially available yet for 54" pipeline 3. Requires high developmental cost 4. Reliability is uncertain

* Development cost of this type of inspection pig to be propelled through the water fluid flow may range from 2 to 5 million dollars for a highly reliable version.

95% (47)

TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
3.2.1(f) Tracking (Inspection pig located in pipeline by monitoring signal from nuclear, acoustic pinger or nuclear source inside inspection or cleaning pig. Also can be an acoustic pinger inside a polyurethane sphere.)	1. Locates stuck inspection or cleaning pig caused by pipeline defects - improper bending or medium or major leaks.	1. Sensitive only to large defects in pipeline	1. Simple locating method 2. Low cost for polyurethane spheres 3. Some incipient failure detection 4. Commercially available	1. Relatively insensitive to most pipeline defects
3.2.2 Inspection Pigs (pushed or pulled through pipeline or hose string via cables, etc.)				
3.2.2(a) Camera (Low-light type camera and video tape or TV monitor)	1. Visually inspect inside of pipeline for cracks, corrosion pits, paint condition, etc. 2. Inspects inside of hose for defects under vacuum	1. Slightly better than visual sensitivity 2. 360° viewing	1. Medium cost 2. Can be used to inspect inside of hoses particularly in evacuated condition 3. Some incipient failure detection 4. High reliability 5. Commercially available 6. Can be stopped for viewing of questionable areas of pipe or hose	1. Requires out-of-service operation 2. Currently limited from 1000 to 3000 ft. 3. Requires winch to pull camera 4. Requires clean, clear water 5. Works best with fresh water
3.2.2(b) Stereo Pairs Camera (strobed light exposures with no camera shutters)	1. Same as above	1. Slightly more sensitive and better pictures than camera	1. Medium cost 2. Can be used to inspect inside of pipeline or hoses 3. Some incipient failure detection 4. High reliability 5. Commercially available	1. Requires a conductive coaxial cable 2. Currently limited to about 3000 ft. 3. Requires clean, clear water
3.2.2(c) Eddy Current (Eddy current changes in non-magnetic tubing caused by defects are detected by a recording impedance bridge - pipeline only)	1. Wall thickness 2. Pits 3. Cracks 4. Holes 5. Corrosion 6. Surface or near-surface defects	1. Longitudinal cracks .1 mm deep by 10mm in length can be detected 2. Changes in wall thickness of 1% in a 10mm length can be detected	1. Medium cost 2. Good incipient failure detection 3. Widely used 4. Commercially available 5. Locates defects near surface	1. Insensitive to circumferential cracks, short cracks and shallow cracks 2. Requires out-of-serivce inspection 3. Non-magnetic materials only 4. Limited to a few 30 foot lengths of pipe
3.2.3 Inspection Pigs with Manned Inspectors (Pushed or internally powered through large pipelines.)				
3.2.3(a) Inspection Methods (See part 5 of this table)	1. All internal defects and pipeline corrosion	1. Best overall sensitivity of any inspection method for pipeline	1. Best overall incipient inspection technique for internal examination of pipeline 2. Operational under limited use	1. Very high cost 2. Slow 3. Requires out-of-service operation 4. Feasibility stage for powered type vehicle
3.2.3(b) Ultrasonic Imaging[20] (Holographic) (See discussion 3.2.1(g). Method was applied to ALYESKA pipeline using manned inspectors and a powered vehicle)	1. Same as 3.2.1(g)	1. Same as 3.2.1(g)	1. Excellent hard copy pictures of internal flow in pipeline 2. Excellent incipient failure detection 3. Simple data interpretations 4. Commercially available	1. High cost 2. Device must be designed and engineered for specific pipeline 3. Reliability uncertain at this time 4. Requires out-of-service inspection
3.3 Hydrostatic-Pressure Drop (Pipeline emptied, pressurized and pressure gages used to detect pressure leaks)	1. Leaks in pipeline, hoses and other OTS components	1. Minor leaks	1. Simple 2. Low cost 3. Provides good incipient failure detection 4. Widely used inspection technique	1. Out-of-service inspection 2. Potential damage to pipeline, hoses or other components 3. Requires leak detection method to locate leaks 4. Downtime for temperature stabilization can be of long duration..
3.4 Reflected Pressure Wave (pipeline must be blocked off, emptied and filled with nitrogen and then pushed with a pressure wave, pressure wave reflects from cracks before it reflects end of pipeline)	1. Internal cracks	1. Detects large cracks of about 2.5 cm.	1. Provides some incipient failure detection 2. Low cost 3. Simple 4. Can be used for pipeline inspection	1. Out-of-service inspection 2. Sensitive to internal surface roughness 3. Experimental technique 4. Currently has only been tested on pipeline 5. Questinable for inspection of hose string

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TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
3.5 Vacuum With TV Inspection Pig (See 3.2.1(e), 3.2.2(a), 3.2.2(b) of Table 3-1.)	1. Internal hose string defects 2. Hose inner cover damage or separation	1. Similar to visual out-of-service inspection	1. Simple 2. Medium Cost 3. Good incipient failure detection 4. Provides inspection for defects that can be found by on-shore inspection.	1. Potential difficulty in interpreting data because of hose bending effects at the time of inspection 2. Difficult to implement
3.6 External Hydrostatic[21] (Device fits over and seals small sections of piping. External pressure is applied and monitored. If an internal leak exists, pressure decrease will occur and the leak detected.)	1. Defects in threaded or welded connections of piping 2. Pipe leaks	1. Better sensitivity than hydrostatic testing	1. Low cost 2. Simple 3. Potentially can be applied to hose flanges and underwater piping 4. Good incipient failure detection 5. Quick test time 6. Commercially available	1. Must be applied externally 2. Not a replacement for conventional non-destructive testing such as X-ray.
3.7 Acoustic Resonance (Locates cracks in gas-filled pipelines by using the "organ pipe" resonances of the gas column in pipeline to measure distance from pipe input to crack in pipeline wall. Requires microphone and sound generator at pipeline input.)	1. Cracks or gouges in pipeline wall	1. Depends upon pipeline radius and wall thickness and wavelength of sound.	1. Low cost 2. Simple 3. Good incipient failure detection 4. Particularly useful in inaccessible areas	1. Requires out-of-service inspection
4.0 CORROSION				
4.1 Corrosion Flow Sampling[22] (Corrosion rate coupons, laboratory analysis of flow content, strainer and pig trap monitoring)	1. Internal pipeline corrosion	1. Potentially can detect major corrosion 2. Corrosion trend indicator	1. Some incipient failure detection 2. Widely used 3. Medium cost 4. Commercially available	1. Difficult to determine quantitatively the amount of corrosion 2. Does not locate corrosion
4.2(a) Corrosion Metering[22] Internal (Corrosion rate probe installed inside at the top of pipeline with an exposed element. Corrosion causes a change in electrical resistance of element.)	1. Internal pipeline corrosion	1. Potentially can detect major corrosion 2. Corrosion trend indicator	1. Some incipient failure detection 2. Widely used 3. Low cost 4. Commercially available 5. Simple	1. Indicates corrosion trend 2. Does not locate corrosion

95%

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TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
4.2(b) Corrosion Metering-External (Potential measurements and continuity measurements of exposed steel of OTS components)	1. External corrosion of pipeline, hose string, SPM and other OTS components	1. Provides adequate measurement of conditions of cathodic protection for most OTS components	1. Simple 2. Low cost 3. Widely used 4. Good incipient failure detection 5. Commercially available	1. Diver inspection required for undersea OTS components 2. No reliable method for submarine pipelines that are greater than 5 miles offshore.
4.2(c) Visual Corrosion Inspection	1. External corrosion of pipeline, hose string, platform structure, and other OTS components.	1. Poor	1. Low cost 2. Simple 3. Some incipient failure detection	1. Subject to personnel error 2. Not quantitative
4.3 Holiday Detector(23) (Device places an electric potential between pipe section and an electrode that is in contact with outside coating of pipe. Electrode typically is a coiled spring around pipe. Electric potential is set high enough so that an arc in air is produced when thickness of coating is not satisfactory .)	1. Coating discontinuities 2. Surface defects	1. Defects of pinhole or microscopic size	1. Simple 2. Some incipient failure detection 3. Commercially available 4. Low cost 5. Indicates if coating is less than ideal	1. Pipe must be uncovered and above water
5.0 NON-DESTRUCTIVE TESTING (Commonly used methods-can be used on most OTS components) (References 19, 24, 25, 26, 27, 28.)				
5.1 Passive Ultrasonics (Portable-hand held, towed fish, etc. - ultrasonic detectors that detect sounds emitted at leak source of hose string, pipeline, SPM, etc.)	1. Leaks 2. Valve damage	1. Minor leaks 2. Detects medium leaks up to about 300 feet away on pipelines	1. Low cost 2. Simple 3. Commercially available for above water or underwater use 4. Some incipient failure detection 5. Leak location	1. Must be very close to leak source if it cannot be attached to leaking structure 2. Leak location only 3. Cannot be used to accurately determine severity of leak

95%

(50)

TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
5.2 Active Ultrasonics (Detector sends ultrasonics wave pulses through or along DWP component and then detects distorted wave pulses or reflection times of returned waves from defect areas.)	1. Internal defects 2. Thickness measurements 3. Corrosion measurements	1. About 1% thickness variations can be detected easily 2. Internal defects such as 10mmL x 1mmW x .3mmH can be detected at distances up to 2 meters away	1. Low cost 2. Widely used inspection method 3. Excellent incipient failure detection 4. Works well underwater 5. Can be used for most materials 6. Commercially available	1. Difficulty in providing a test report of internal defects because of interpretation difficulty
5.3 X-Ray (Radiographic method uses X-ray source to penetrate through a material. Intensity of penetration is modified by passage through material and defects. Visible contrast on film shows defect free area and defect.)	1. Internal defects 2. Thickness measurements 3. Corrosion	1. Excellent sensitivity-about 1% of thickness variations can be detected 2. Poor resolution of thin horizontal cracks 3. Gives average wall thickness for through pipe inspection	1. Can be used for almost any material 2. X-ray records easy to interpret 3. High reliability 4. Commercially available 5. Excellent incipient failure detection	1. High cost 2. Poor penetration through water 3. Seldom used underwater 4. Radiation safety measures required 5. High voltages are cause for problems underwater 6. Cumbersome equipment
5.4 Radio Active Isotopes Gamma Ray (Same type of operation as 5.3 but a radioactive source is used instead of X-ray source. Source and detector film at 180°, for on land inspections Source and detector can also be on same side for back scatter method.)	1. Internal defects 2. Thickness measurements 3. Corrosion	1. Less sensitive than X-ray 2. Defects about 2mm length and 1mm depth can be detected underwater 3. Gives average wall thickness for through pipe inspections 4. Provides severity of flaw	1. Can be used for any materials 2. Commonly used underwater 3. Records easy to interpret 4. Highly reliable 5. Excellent incipient failure detection particularly for underwater use 6. Commercially available	1. High cost 2. Requires captivated system for underwater use 3. Poor penetration through water 4. Radiation safety measures required 5. Slow inspection
5.5 Magnetic Particle (Magnetize inspected component apply and magnetic particles to magnetized area. If flaw is close to surface, magnetic particles will deposit themselves along flaw because of leakage in magnetic flux at the discontinuities.)	1. Essentially all defects at or near surface	1. Highly sensitive for surface or subsurface flaws. 2. Defects about 1mm in length can be detected 3. More sensitive than penetrant method	1. Simple 2. Can be used underwater 3. Low cost for above water 4. High reliability 5. Excellent incipient failure detection 6. Commercially available	1. Can only be used on ferromagnetic materials 2. Sudden changes in permiability produce false defect 3. Medium cost for underwater use 4. Poor permanent records if underwater photos required 5. Demagnetization is usually required.
5.6 Magnetic Rubber (Method the same as 5.5 except magnetic particles suspended in a curing rubber vehicle that is the permanent record after cure.)	1. Essentially all defects at the surface or subsurface	1. Very high sensitivity-defects 0.1 to 0.15 mm in length can be detected	1. Simple 2. Can be used underwater 3. Excellent permanent records 4. Particularly useful in small confined areas or in areas of poor illumination or visual inspection difficulties 5. Commercially available 6. Low cost 7. High reliability	1. Can only be used on ferromagnetic materials 2. Sudden changes in permeability produce false defect 3. Can be used underwater but not much information available for sensitivity or reliability for DWP underwater application.
5.7 Magnetic Foil or Magnetic Tape (Same operation as 5.6 except a foil or tape is used to contain magnetic particles.)	1. Essentially all defects at the surface of subsurface	1. Less sensitive than magnetic rubber but more sensitive than magnetic particle for underwater use	1. Simple 2. Can be used underater 3. Most reliable NDT underwater inspection method 4. Good permanent records 5. Low cost	1. Can only be used on ferromagnetic materials 2. Sudden changes in permeability produce false defect
5.8(a) Ultrasonic (Holographic) Imaging) (Similar to other kinds of holography but uses an array of transducers for high frequency coherent sounds in order to penetrate inside structure for 3-dimensional acoustic image view of interior of solid. Device includes scanning head and ultrasonic holography computer signal processor to recreate image. For underwater use includes video camera and light source)	1. Defects inside the material in 3 dimensions 2. Corrosion/erosion 3. Pits, cracks, etc. 4. Loss of material on inside or outside of pipe weld	1. Flow areas of about 0.2mm x 0.2 mm 2. Instrument can be set up to meet any API specification 3. Thickness resolution of about 0.05mm 4. Provides length, width, shape and depth of crack 5. Penetrates to about 1 meter in solid steel or 0.3 meters of rubber	1. Good hard copy picture of internal flaw with little or no interpretation of data required 2. Has been used underwater with good success 3. Device can be hand held or attached to pipeline 4. Excellent incipient failure 5. Commercially available in 1978 6. Potentially can be used for hoses particularly at nipple section 7. Simple interpretation of data	1. Medium cost 2. Device has been used successfully for a number of underwater applications and needs engineering design for specific application 3. Reliability and performance specification are uncertain at this time

95%

(51)

TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
5.8(b) Optical Holography Imaging (Similar to ultrasonic imaging holography. The signal processor provides optical picture of data in 3-dimension. Uses coherent light sources and an ultrasonic holographic computer signal processor to recreate images.)	1. Surface flows such as cracks, voids, etc. 2. Sense surface defects after structure is stressed	1. 3-dimensional images show length, width geometry and depth 2. Resolution equal to wavelength of energy being used	1. Permanent record of data at surface of material 2. Good incipeint failure detection 3. Commercially available	1. High cost 2. Above water use only
5.9 Eddy Current (A detector coil carrying alternating current is brought near a material specimen and eddy currents are induced by electromagnetic induction. Discontinuities in material change the magnitude of induced eddy current.)	1. Internal defects 2. Cracks 3. Thickness 4. Voids 5. Corrosion	1. Above water cracks - 0.2 to 0.4mm sensitivity 2. Below water cracks - about 0.4mm x 10mmL	1. Locating defects near surface 2. Low cost 3. Simple 4. Commercially available 5. Good incipient failure detection for above water use and some incipient failure detection for underwater use 6. Works well on thin materials	1. Poor reliability for underwater use 2. Does not work in non-metals 3. Needs development for reliable underwater use
5.10 Penetrants (A liquid penetrant is applied to the inspected surface. After sufficient penetrating time, the excess penetrant is wiped off and a white powder is typically applied to the surface. After a period of time penetrant seeps out of crack and reduces the whiteness of the powder and the defect can be observed.)	1. Surface cracks, laps 2. Internal defects with surface openings	1. Above water cracks, defects, etc. of about 1 mm width. 2. Much more sensitivity than visual inspection	1. Simple 2. Covers a large area 3. Low cost 4. Commercially available 5. Good incipient failure detection above water	1. Cannot be used underwater 2. Will not work with surfaces covered with oil, grease, paint, etc. 3. Needs research and development for underwater use
5.11 Bolt Tightness (Torque) (Common torque wrench)	1. Bolt tightness	1. Standard torque wrench accuracy	1. Simple 2. Low cost 3. Insures bolt tightness specifications 4. Can be used on land or underwater 5. Commercially available 6. Some incipient failure detection	
6.0 SURVEY (29),(30),(31),(32) (For undersea pipelines, SPM pumping platform, anchors, PLEM base, etc.				
6.1(a) Sonar-Sidescan (Inspects for topographical features and bare spots in pipelines. An acoustical transducer in a towed fish (travelling close to the sea bottom) sends a pulsed and almost horizontal beam. The strength of the echo of the transmitted beam provides sufficient information to determine size and orientation of pipeline bare spots.)	1. Bare spots in the undersea pipeline 2. Pipeline orientation	1. Exposed undersea pipeline surfaces as small as 2.54 cm	1. Provides excellent incipient failure detection 2. Fast inspection 3. Covers wide area 4. Low cost 5. Commercial systems or services available 6. Method can be used simultaneously with sub-bottom profiling inspection to obtain depth of pipeline burial	1. Requires skilled interpretation of data

95% (52)

TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
6.1(b) Sonar-Penetrating Sub-Bottom Profiling (Two acoustical transducers, one penetrating through overburden of pipeline and one that reflects from pipeline overburden, are towed in a tow fish. Transducers send pulsed vertical beams. The strength of reflected echos provide sufficient data to determine depth of burial)	1. Depth of burial 2. Trench delineation 3. Pipeline locations and orientation	1. Depth of burial to 5 cm	1. Provides excellent incipient failure detection 2. Fast inspection 3. Covers wide area 4. Low cost 5. Commercial systems or services available	1. Requires skilled interpretation of data
6.2 Surveying-Component Location(32)				
6.2(a) Diver Using Microwave Position System(32) (Diver walks the pipeline and will hold a taunt buoy line. A microwave positioning system antenna is mounted over the buoy and is used to accurately locate the position of a diver)	1. Precise pipeline location 2. Pipeline damage	1. Precise pipeline location to 200 meters of water depth	1. Covers up to about 1/2 mile per day 2. Can be used in turbid water 3. Provides visual inspection by diver 4. Particularly useful for new pipelines 5. Excellent incipient failure detection 6. Inspection services available	1. High cost 2. Currently limited to about 20 meters of water depth
6.2(b) Diver Using Acoustic Transponder System(32) (Diver walks pipeline and transmits position with an acoustic transponder with a 1° beam)	1. Precise pipeline location 2. Pipeline damage	1. Precise pipeline location to 200 meters of water depth.	1. Same as for 6.2(a) except item 6 2. Diver can leave a locating transponder at an area where pipe needs repair. This allows easy location for later repairs	1. High cost 2. Development stage
6.2(c) Misc. Systems See Appendix B.6.2(c)				
6.3 SCOUR				
6.3(a) Diver Visual Inspection	1. Identifies unprotected areas caused by scouring that can result in excessive corrosion	1. Visual	1. Simple 2. Low cost 3. Some incipient failure detection	1. Visual only and subject to interpretation 2. Cannot find scour areas that may be covered up by current after storm
6.3(b) Diver Inspections with Pneumofathometer Device (Diver uses hand held hose to probe bottom surface around the OTS component. Air is inserted into the hose from diver supply ship. A gage on the supply ship is used to measure pressure of the hose line in feet of sea water to determine bottom surface depth.)	1. Identifies unprotected areas caused by scouring 2. Corrosion 3. Bottom topography	1. Visual 2. Accurate bottom topography measurement	1. Simple 2. Low cost 3. Some incipient failure detection	1. Cannot find scour areas that may weaken structure but may be covered up after storm
6.3(c) Continuous Monitoring (See Appendix B.6.3(c) for methods and reference 30 for discussion of methods)	1. Continuous scour monitoring	1. Scour resolution to within a foot	1. Detect scour areas that may weaken structure but may be covered up by storm 2. Continuous monitoring 3. Especially useful in deep water where diver or submersible vehicle inspections are costly 4. Good incipient failure detection	1. Medium cost 2. Not particularly advantageous at short depths (i.e., 50 meters) from a cost consideration 3. Systems require development and engineering design

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TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
7.0 OTS CONTROL				
7.1(a) Pressure-Static (Monitors OTS line integrity when a line segment is shut down. Pressurize line at a nominal operating pressure and monitors pressure for any pressure drop.)	1. Oil leaks	1. Medium oil leaks 2. Less sensitive than hydrostatic pressure difference method	1. Low cost 2. Simple 3. Good incipient failure detection 4. Commonly used method 5. Commercially available	1. Requires leak detection method if leaks are monitored. 2. Variations in temperature, hose string movements, etc. limit sensitivity of leak inspection. 3. Difficult to detect slow leaks.
7.1(b) Pressure Deviation - Continuous (Monitor of discharge pressure at ship and pressures at SPM, pumping platform and onshore.)	1. Oil leaks	1. Major oil leaks	1. Low cost 2. Simple 3. Commonly used 4. Commercially available 5. Some incipient failure detection for hose strings.	1. Catastrophic failure only
7.1(c) Volume Comparison (Flow Quantity) - Continuous (Volume comparison based on time intervals of several minutes duration to check metered barrels into pipeline against metered volume out. Comparison of volume measurements typically occurs over hourly periods.)	1. Oil leaks	1. Medium or major oil leaks 2. Large leaks over a short period of time and small leaks over a long period of time	1. Simple 2. Commercially available 3. Continuous inspection	1. Detects leaks after they occur 2. Difficult to detect slow leaks that over a period of time may result in a major oil spill 3. Cannot detect a catastrophic failure in sufficient time to prevent major oil spill 4. Tendency by operators to raise set-points to reduce false alarms because of line pack and other considerations 5. Detects leak only once per hour for most commonly used systems 6. Medium cost
7.2 Flow Rate Comparison - Continuous ≈ 1% accuracy (Flow rate measurements at each end of the OTS system are compared. Large differences in measurement indicate possibility of leakage.)	1. Oil leaks	1. Major oil spills	1. Simple 2. Detects catastrophic failure 3. Commercially available 4. Commonly used 5. Continuous inspection	1. No incipient failure detection 2. Usually used only from pumping platform to onshore terminal 3. Tendency by operators to raise set-points to reduce false alarms and thus decrease leak sensitivity
7.3 Mathematical Modeling - Continuous ≈ 0.1% Accuracy (Computerized method of modeling OTS pipeline or hose string system (components, sizes, materials, etc.) and flow characteristics (temp., pressure, viscosity, etc.) to optimize leak sensitivity.)	1. Oil leaks	1. Detects leaks ≈0.1% of actual flow rate 2. Small to medium leaks 3. Detects leaks when flow reaches flow meters	1. Low cost 2. Computerized data reduction 3. Good incipient failure detection 4. Provides leak detection improvements over conventional hydrostatic pressure tests 5. Can be used in conjunction with supervisory control systems 6. Requires only repeatable rather than high accuracy flow meter 7. Commercially available 8. Continuous inspection	1. Medium cost if transducers must be added to existing supervisory control system 2. May require trained personnel to properly interpret data or maintain systems
7.4 Negative Surge - (Leak Pressure Wave Detection (Large Rupture type leak causes negative pressure wave along OTS pipeline that can be detected and located.)	1. Oil leakage	1. Leakage > 600 barrels per hour 2. Leak location within 2 miles	1. Continuous inspection 2. Commercially available 3. Supplements other methods (7.2 and 7.3)	
8.0 SPECIAL METHODS (11), (33)				
8.1 Passive Acoustic Array-Leaks (Array of acoustic transducers permanently installed on OTS component to detect and locate leak from sounds emitted at the source of a leak. Method can be used for pipelines, hoses, valves, etc.)	1. Oil or gas leaks-detection and location	1. Depends on material, OTS component structure transducer spacing, etc. 2. Potentially can detect a small, slow leak (i.e., few barrels per hour) and locate the leak within a few feet 3. Sensitivity increased with application of higher test pressures or a test gas.	1. Simple 2. Excellent incipient failure detection 3. Requires little or no interpretation by personnel 4. Computerized, automated system can be adapted to existing OTS control system 5. Can be used underwater 6. Can be used during normal OTS operations 7. Permanent records 8. Can be used in all kinds of weather and in darkness	1. Medium cost 2. System in development/engineering phase 3. Reliability and performance specifications are uncertain, DWP testing required.

95% (54)

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TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
8.2 Passive Acoustic Array-Acoustic Emission (Array of acoustic transducers installed on OTS components to detect and locate repetitive acoustic emission sounds generated at the source of the flawed material that is under stress or under impact. Can be used on hose string, pipeline, valves, etc.)	1. Material defects 2. External impacts such as from anchor dragging 3. Valve damage 4. Mooring system failure	1. Depends on material, OTS component structure, transducer spacing, etc. 2. Can detect and locate internal flows that are growing and prior to catastrophic failure 3. Sensitivity increased with application of stresses higher than normally used	1. Excellent incipient failure detection 2. Computerized automatic system can be adopted to existing OTS control 3. Commercial system for periodic proof testing of tanks, pressure vessels, etc. are available 4. Can be used underwater 5. Can be used during normal OTS operations 6. Permanent records 7. Can be used at all times	1. Incipient failure data subject to interpretation as to the severity of defect but system does provide defect location for further inspections by other means 2. Medium cost 3. Reliability and performance specifications for hose string application are uncertain.
8.3 Passive Acoustic Machinery Damage [34] (Acoustic transducers hand held or permanently installed on machinery detect abnormal sounds emitted when internal defects start to occur in machinery. Strain transducers or accelerometers can also be used for this detection. System usually provide continuous monitoring and alarms.)	1. Internal defects in machinery 2. Bearing damage 3. Valve damage		1. Commercial system available 2. Good incipient failure detection 3. Reduces machinery maintenance cost 4. Permanent records 5. Continuous monitoring	1. Data subject to interpretation as to the severity of internal defect but systems typically give adequate warning before a failure can occur.
8.4 Strain Gaged Mooring Load Monitor [35] (Continuous monitoring of mooring loads at SPM buoy using strain gaged load cells. Provides continuous recordings and alarm for excessive loading and ship breakout)	1. Excessive loads 2. Mooring line failure 3. Mooring line load history	1. Approximately 5% of mooring system loads	1. Not effected by weather 2. Excellent incipient failure detection 3. Permanent records 4. Commercially available 5. Provides history of mooring loads 6. Continuous monitoring 7. Detects ship breakout	1. Medium cost 2. Reliability and performance are uncertain under DWP environment
8.5(a) Laser Detection [11] Underwater Leaks (A laser system would be mounted on an underwater pipeline or hose string. The laser is aimed parallel to the pipe or hose to a detector mounted further away. Light transmittance would decrease with oil escaping. Thus a leak can be detected)	1. Oil leaks	1. Depends on laser source and power, detector sensitivity and traverse 2. Minor spill sensitivity expected	1. Some incipient failure detection 2. Continuous monitoring	1. Feasibility stage for underwater 2. High cost 3. Environment that the equipment is subjected to makes practical application difficult at best 4. Detects leaks only after they occurs 5. Requires highly trained personnel
8.5(b) Laser Detection-Above Water Oil Leaks (Laser placed on high land. System traverses fixed plane along pipeline or hose string. Since laser absorption by oil and water is known, a leak can be detected.)	1. Oil leaks	1. Depends on laser source and power, detector sensitivity and traverse 2. Minor or medium spill sensitivity expected	1. Can be used above water, on shore, on platform or on deck of ship 2. Continuous monitoring	1. High cost 2. Requires trained personnel 3. Affected by bad weather 4. Detects leaks only after they occur and oil rises to the surface 5. Developmental/engineering stage for DWP usage
8.6 Shroud with EMP [11] Pulsed Coaxial Cable (A shroud is placed above or around pipeline, hose or other OTS component to collect oil from a leak. A special continuous coaxial cable would have breaks in the outer cover which would be bridged by salt water. An electromagnetic pulse would be sent down the cable and would pass through entire length of cable and, with a short circuit electrical terminations, would be reflected back (inverted) to the sending end. An oil leak would cause the reflected wave to be sent back non-inverted.)	1. Oil leaks	1. Minor spills 2. Minute leaks can be detected and then located within a few feet	1. Simple 2. Can be used with OTS control system 3. Continuous monitoring 4. Good incipient failure detection	1. Unproven at DWP 2. Reliability uncertain 3. Detects leaks after they occur 4. Medium cost

95%

55

TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
8.7 Double Walled Pipe (11) (Requires double walled pipe with the one transferring fluid to be centered inside the other. A variety of adequate oil detectors could be installed on the inside of the outer pipe to detect leaks from the inner pipe.)	1. Oil leaks	1. Small or minor leaks 2. More sensitive than any other method for pipelines	1. Simple 2. Excellent incipient failure detection 3. Continuous inspection 4. Contains the leaked oil thus preventing spill 5. Cost effective for short sections of piping located at potential leak areas	1. Very high cost
8.8 Double Walled Hose (Requires double walled hose with the one transferring fluid as the inside hose. Leaks of the inner hose cause the outer more elastic hose wall to expand and bulge. This can easily be seen by visual inspection)	1. Oil leaks	1. Small or minor leaks	1. Simple 2. Excellent incipient failure detection 3. Commercially available for some sections of the hose string 4. Contains the leaked oil thus preventing small oil spills	1. Reliability uncertain because damage to the outer cover may allow leaks rather than bulging of the outer cover 2. High cost 3. Damage of the inner hose can occur and cannot be detected by visual inspection 4. Hoses stiff
8.9 External Load (Apply external test loads to various OTS components-eg. chains, hawsers, etc.)	1. Internal flaws 2. Damage not visible	1. Require visual inspection or other inspection method to detect and locate flaws	1. Simple 2. Some incipient failure detection 3. Can be used to calibrate other inspection systems	1. Medium cost
8.10(a) Seal Leak Detector Thermistor Type (36) (Portable heated thermistor device senses gas leaks through a seal that is placed over test area. Thermistor exhibits large changes in resistance with small changes in temperature caused by the leaking gas. Method can be used for tanks, pipelines, hoses and other OTS components.)	1. Gas leaks	1. 10^{-8} scc/s for nitrogen gas	1. Simple 2. Low cost 3. Good incipient failure detection	1. Requires out-of-service inspection 2. Developmental/engineering stage 3. Has not been developed for underwater use
8.10(b) Seal Leak Detector - Joint Type (End element tubes wrapped around a cylindrical fixture are positioned on each side of a joint and pressurized to provide a good seal. Then area in between the tubes is pressurized and this pressure is monitored with a gage. Decrease in gage pressure will indicate leak)	1. Air or liquid leaks inside pipe or hose string seals	1. Very small seal leaks	1. Simple 2. Low cost 3. Can potentially be used to check leaks in flange seals of hose strings 4. Commercially available 5. Good incipient failure detection 6. Reduces the need to pressurize lines	1. Requires out-of-service inspection 2. May need some development for DWP usage
8.10(c) Seal Leak Detector Capacitor type (Insulated capacitive material is placed inside two connecting flanges that contain a seal. Air or water leaks change capacitance and impedance of the capacitive material)	1. Oil, gas or water leaks in flanges and other types of seals	1. Better than 10^{-3} scc/s	1. Simple 2. Low cost 3. Good incipient failure detection 4. Commercially available 5. Continuous monitoring	1. Requires detector to be designed as part of the OTS component 2. Has not been tested for DWP environment

75 56

TABLE 3-1 (Continued)

INSPECTION METHOD	DEFECT MEASURED	SENSITIVITY	ADVANTAGES	DISADVANTAGES
8.11 Liquid Level Sensor (Detects level of liquid in tanks, piping, etc. using any one of many available methods-ultrasonic, optical, microwave, nuclear, etc.)	1. Oil levels 2. Oil leaks into containers	1. Better than 1%	1. Simple 2. Low cost 3. Some incipient failure detection 4. Commercially available 5. Continuous monitoring	
8.12 Continuous Thermistor (Device installed on outside and along the pipe. Oil leaks change the properties of the continuous thermistor-type cable.)	1. Oil leaks	1. Unknown	1. Continuous monitoring	1. Medium Cost 2. Feasibility stage for DWP use
9.0 MISCELLANEOUS METHODS				
9.1 Hydrocarbon Probe (Sniffer) (Hydrocarbon probe is installed in towfish and towed a few meters above the pipeline. Probe detects hydrocarbons from oil leaks. A pressure sensor in towfish measures depth.)	1. Oil leaks in pipeline 2. Oil that may settle on the bottom	1. 5×10^{-9} ml gas per ml water	1. Simple 2. Low cost 3. Commercially available 4. Good incipient failure detection 5. Provides continuous record	
9.2 Laser Holography (Surface to be inspected is irradiated with laser and high resolution film is exposed by laser light reflected from surface. Developed film produces a 3-dimensional hologram. If surface undergoes a topographical change, another exposure is made on the same film and minute changes in topography can be recorded. Changes can be detected by fringe patterns shown in holographic reconstruction.) (37)	1. Small topographical changes	1. Wavelength of laser light	1. Commercially available 2. Some incipient failure detection for hoses	1. Medium to high cost 2. Requires trained personnel 3. Very difficult to implement for use on DWP installed OTS components 4. Very limited inspection use
9.3 Magnetic Chip (Installed on machinery and periodically examined.)	1. Internal defects in machinery 2. Bearing damage		1. Simple 2. Low cost 3. Commercially available 4. Same incipient failure detection 5. Reduces machinery maintenance costs 6. Continuous monitoring	
9.4 Oil Odor	1. Oil Leaks	1. Small leaks	1. Simple 2. Can be used in darkness or in bad weather 3. Good incipient failure detection	1. Subject to personnel error 2. Winds may cause oil odor not to be detected 3. Not quantitative
9.5 Other Methods (Other miscellaneous methods with limited application - see Appendix B.9.5.)				

95% (57)

The diver inspections identified in Table 3-1 will be carried out by qualified divers and necessary support personnel using the following general inspection procedures:

(1) Inspection surveys will be recorded by videotape, photographs or other equivalent techniques and a written report submitted;
(2) Extent and nature of marine growth will be recorded;
(3) High pressure cleaning, wire brushing, etc., will be performed on all underwater components prior to visual inspection;
(4) Tankers shall not be moored to buoy and calm sea state must be forecast to 48 hours unless indicated otherwise;
(5) A diving platform may be required during certain sea states in the Gulf of Mexico;
(6) All U.S. diving regulations and other complimentary regulations will be followed (for example see References 38, 39, 40).

Appendix B.1.3 provides more detailed information on diver inspection procedures.

3.2 HOSE STRING, MOORING SYSTEM AND SHIPBOARD CONNECTIONS

Hose string, mooring system and shipboard connections for hypothetical deepwater ports are shown in Figures 3-1 and 3-2 for Single Anchor Leg Mooring and Cantenary Anchor Leg Mooring systems. Table 3-2 identifies potential inspection methods that can be used for inspecting the basic components that are generally used for these three OTS subsystems. Inspection methods for conditions when a ship is either offloading or moored to the buoy are included for both the hose string and mooring system.

3.3 UNDERSEA PIPELINES

Potential inspection methods for detection of the failure modes of OTS undersea pipelines are given in Table 3-3. The effectiveness of the inspection methods depends upon a number of considerations

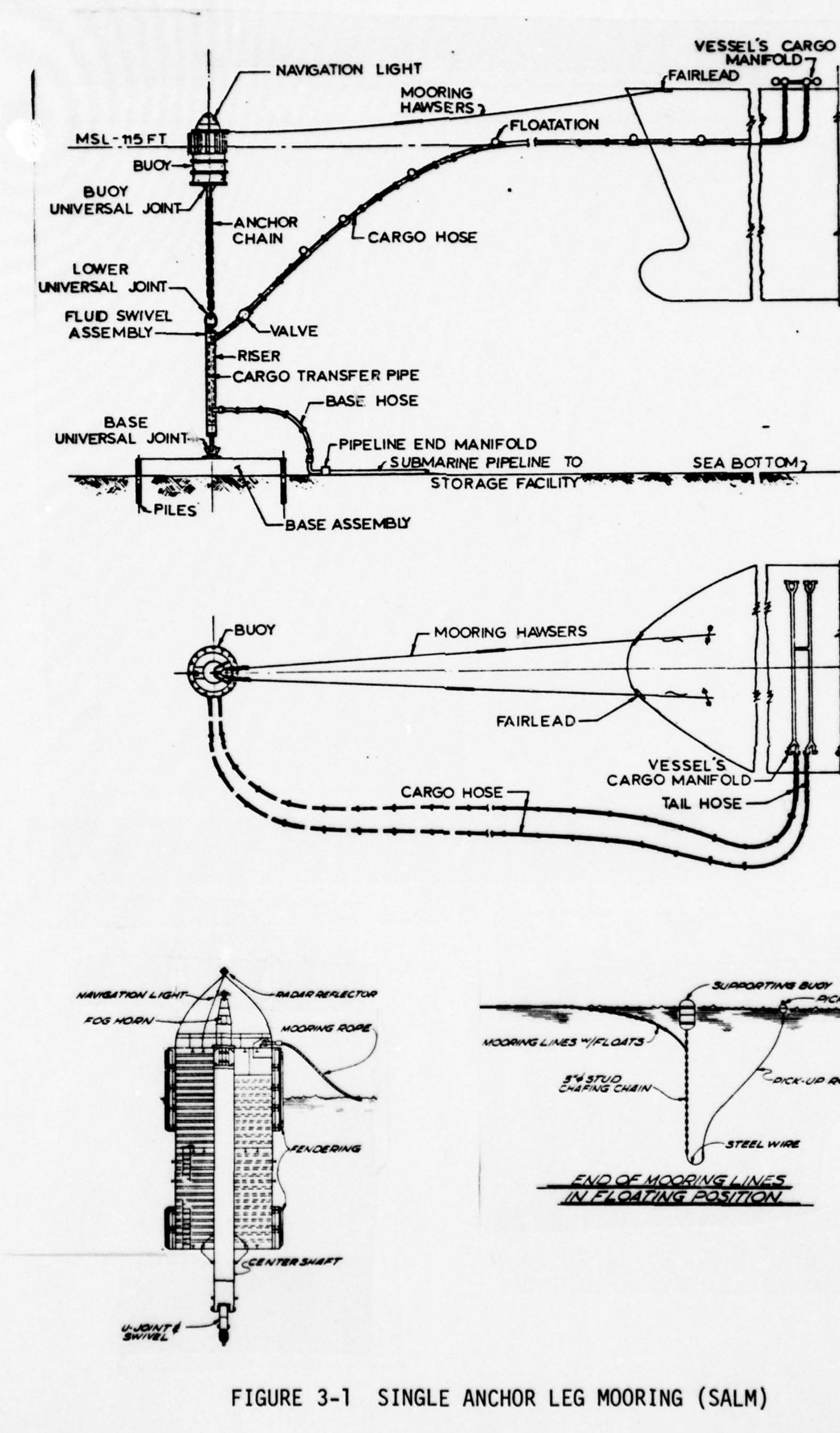

FIGURE 3-1 SINGLE ANCHOR LEG MOORING (SALM)

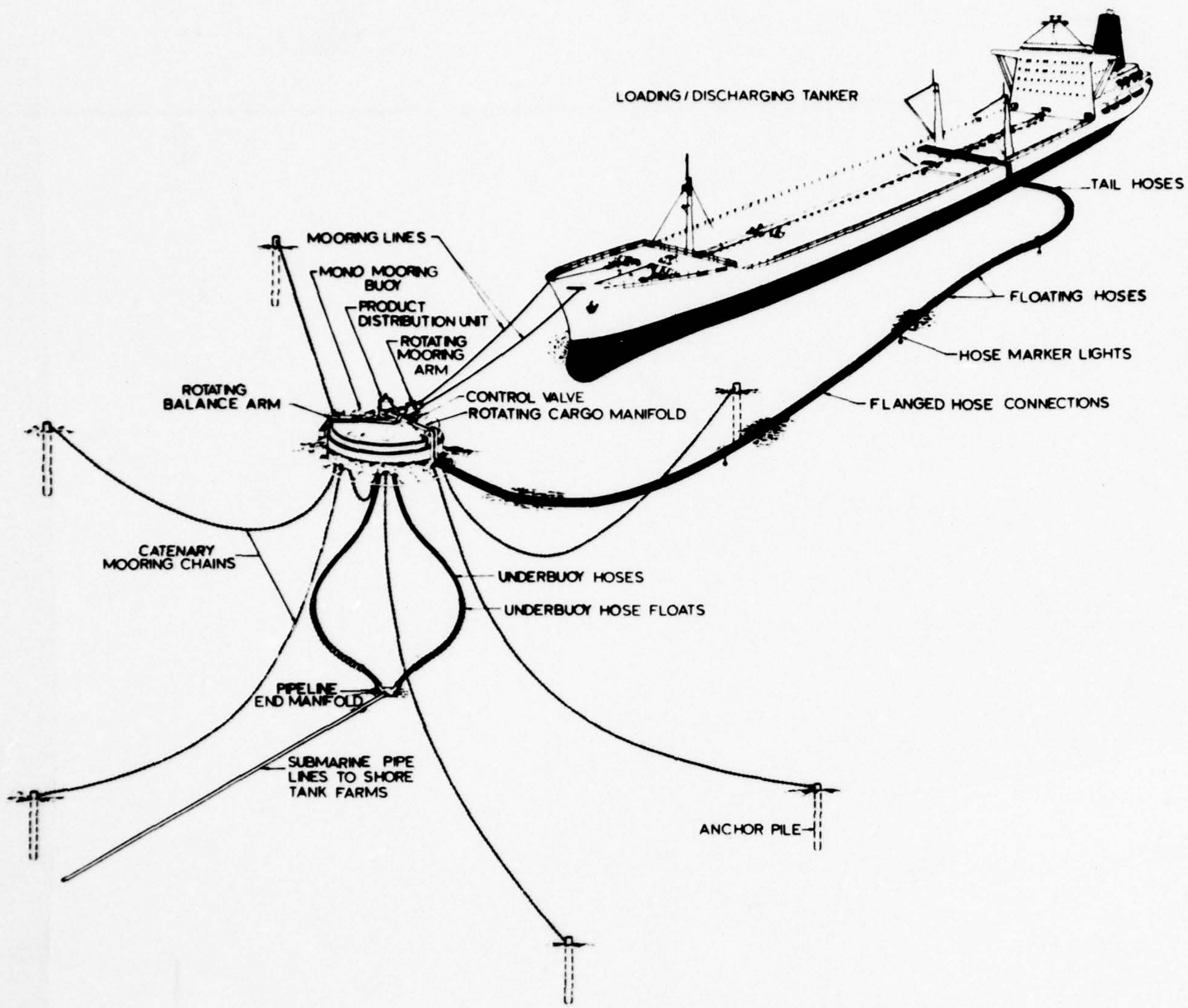

FIGURE 3-2 GENERAL ARRANGEMENT OF CATENARY ANCHOR LEG MOORING (CALM)

TABLE 3-2 HOSE STRING, MOORING SYSTEM AND SHIPBOARD CONNECTIONS-INSPECTION METHODS

OTS COMPONENTS / INSPECTION METHODS	1 VISUAL: Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	2 OIL SPILL DETECTOR: Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	3 DYNAMIC INSERTIONS INTO OTS: Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic
HOSE STRING DURING OFFLOADING																		
Floating Hose String	●	●		c		●		●	●		c	●						
Floating Hoses (Includes Nipples, Flanges, Seals, Bolts)	●	●		c		●	●	●	●		c	●						
Anticollision Blinker Lights	●	●				●												
Flanges and Bolts	●					•	•	•										
Flange Seals	●						•											
Flotation Collar	●	●		c		●												
Floats	●	●		c		●												
Brackets and Bolts	●					●												
Gaskets and Bolts	●																	
Spreader Bars and Bolts	●			c		•												
Tail Hoses	●	●		c		•	•	●	●			●						
Pickup Buoys and Support Rope	●	●		c		•												
Chain	●	●		c		•												
Butterfly Valve	●	●				•												
Submarine Hose String								●	●		●	●						
Submarine Hoses (Includes Nipples, Flanges, Seals, Bolts)	●	●		●		P		●	●		●	●						
Flanges and Bolts																		
Flange Seals																		
Spreader Bars																		
Body Floats																		
Buoyancy Tanks																		
Brackets and Bolts																		
Gaskets and Bolts																		
HOSE STRING NOT DURING OFFLOADING																		
Floating Hose String	●		●		●	•		●			c	•	●	●	●		●	
Floating Hoses (Includes Nipples, Flanges, Seals, Bolts)	●		●	c	●	●	●	●			c	•	●	●	●		●	P
Anticollision Blinker Lights	●			c	●													
Flanges and Bolts	●		●	c	●	•		●					●		●			P
Flange Seals	●		●			•		●					●		●			●
Flotation Collar	●		●	c	●													
Floats	●		●	c	●													
Brackets and Bolts	●		●	c	•										•			
Gaskets and Bolts	●		●			•							P		●			
Spreader Bars and Bolts	●		●	c	●													
Tail Hoses	●		●	c	●	●		●				•	●		●		●	•
Pickup Buoy and Support Wire Rope	●		●	c	●													
Chain	●		●		•													
Blind Flange and Bolts	●		●	c	•	•		●				•	●		●			
Butterfly Valve	●		●	●	•			●					●		●			

OTS COMPONENTS / INSPECTION METHODS	4 CORROSION: Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont., Visual)	Holiday Detector	Cathodic Protection (Mfg. Schedule)	5 NON-DESTRUCTIVE TESTING: Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements
HOSE STRING DURING OFFLOADING																
Floating Hose String	•															
Floating Hoses (Includes Nipples, Flanges, Seals, Bolts)	•															
Anticollision Blinker Lights																
Flanges and Bolts	•															
Flange Seals																
Flotation Collar																
Floats																
Brackets and Bolts																
Gaskets and Bolts																
Spreader Bars and Bolts																
Tail Hoses	•															
Pickup Buoys and Support Rope																
Chain																
Butterfly Valve																
Submarine Hose String	•															
Submarine Hoses (Includes Nipples, Flanges, Seals, Bolts)	•															
Flanges and Bolts	•															
Flange Seals																
Spreader Bars																
Body Floats																
Buoyancy Tanks																
Brackets and Bolts																
Gaskets and Bolts																
HOSE STRING NOT DURING OFFLOADING																
Floating Hose String																
Floating Hoses (Includes Nipples, Flanges, Seals, Bolts)		●		●	P	●	•	•	•	•	●	●	•	•	●	•
Anticollision Blinker Lights															●	
Flanges and Bolts		●		●	P	●	•	•	•	•	●	•	•	•	●	
Flange Seals					P										●	
Flotation Collar															●	
Floats															●	
Brackets and Bolts		●		●		●	•		•	•	●	•	•	•	●	
Gaskets and Bolts					●	●									●	
Spreader Bars and Bolts		●		●		●	•	•	•	•	●	•	•	•	●	
Tail Hoses		●		●	P	●	•	•	•	•	●	●	•	•	●	•
Pickup Buoy and Support Wire Rope		●		●		•	•	•							●	
Chain		●		●		●	•	•	•	•	●	•	•	•	●	•
Blind Flange and Bolts		●		●	●	●	●	•	●	•	●	•	●	●	●	
Butterfly Valve		●		●	●	●	•	•	•	•	●	•	•	●	●	

OTS COMPONENTS / INSPECTION METHODS	6 SURVEY: Sonar (Bare-Surface, Overburden)	Surveying-Component Location	Scour	7 OTS CONTROL: Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	8 SPECIAL METHODS: Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor
HOSE STRING DURING OFFLOADING																		
Floating Hose String				●	●	●	●	●		•	•	•	●					
Floating Hoses (Includes Nipples, Flanges, Seals, Bolts)							●	●		•	•	•	●		●		•	
Anticollision Blinker Lights																		
Flanges and Bolts							•	•					P				•	
Flange Seals							•	•					•				•	
Flotation Collar																		
Floats																		
Brackets and Bolts																		
Gaskets and Bolts							•	•									•	
Spreader Bars and Bolts																		
Tail Hoses							●	●		•			•		P			
Pickup Buoys and Support Rope																		
Chain										•								
Butterfly Valve																		
Submarine Hose String				●	●	●	●	●		•	•	•	●					
Submarine Hoses (Includes Nipples, Flanges, Seals, Bolts)							●	●		•	•	•	●		●		•	
Flanges and Bolts							•	•					•				•	
Flange Seals							•	•					•				•	
Spreader Bars																		
Body Floats																		
Buoyancy Tanks																		
Brackets and Bolts																		
Gaskets and Bolts							•	•									•	
HOSE STRING NOT DURING OFFLOADING																		
Floating Hose String				•	•	•	●	●				•	●					
Floating Hoses (Includes Nipples, Flanges, Seals, Bolts)							●	●				•	●		●		●	
Anticollision Blinker Lights																		
Flanges and Bolts							•	•									●	
Flange Seals							•	•									●	
Flotation Collar																		
Floats																		
Brackets and Bolts																		
Gaskets and Bolts							•	•									●	
Spreader Bars and Bolts																		
Tail Hoses							●	●				•	●				●	
Pickup Buoy and Support Wire Rope																		
Chain																		
Blind Flange and Bolts							●	●									•	
Butterfly Valve							•	•									•	

OTS COMPONENTS / INSPECTION METHODS	9 MFG - MISC: Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off	Procedure-Water Left in Hose String
HOSE STRING DURING OFFLOADING				
Floating Hose String	●		●	
Floating Hoses (Includes Nipples, Flanges, Seals, Bolts)	●		●	
Anticollision Blinker Lights				
Flanges and Bolts				
Flange Seals				
Flotation Collar				
Floats				
Brackets and Bolts				
Gaskets and Bolts				
Spreader Bars and Bolts				
Tail Hoses				
Pickup Buoys and Support Rope				
Chain				
Butterfly Valve	●	●		
Submarine Hose String	●	•	●	
Submarine Hoses (Includes Nipples, Flanges, Seals, Bolts)	●		●	
Flanges and Bolts				
Flange Seals				
Spreader Bars				
Body Floats				
Buoyancy Tanks				
Brackets and Bolts				
Gaskets and Bolts				
HOSE STRING NOT DURING OFFLOADING				●
Floating Hose String	●		●	●
Floating Hoses (Includes Nipples, Flanges, Seals, Bolts)	●		●	●
Anticollision Blinker Lights				
Flanges and Bolts				●
Flange Seals				●
Flotation Collar				
Floats				
Brackets and Bolts				
Gaskets and Bolts				●
Spreader Bars and Bolts				
Tail Hoses				●
Pickup Buoy and Support Wire Rope				
Chain				
Blind Flange and Bolts				●
Butterfly Valve	●	●		●

NOTE:

1. Legend - • Potential Method; c Potential Method CALM ONLY; P Potential Method for Inspection of Part of Component; ● Method Selected for Cost-Effective Analysis in Section 4.4
2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

3-19 95%

(61)

TABLE 3-2 (CONTINUED)

INSPECTION METHODS — 1 VISUAL; 2 OIL SPILL DETECTOR; 3 DYNAMIC INSERTIONS INTO OTS

OTS COMPONENTS	Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic
HOSE STRING NOT DURING OFFLOADING (Continued)																		
Submarine Hose String	●		●		●	•		●			C	•	●	●	●		●	
Submarine Hoses (Includes Nipples, Flanges, Seals, Bolts)	p		●		●	•	p	●			C	•	●	●	●		●	•
Flanges and Bolts			●										●		●			
Flange Seals			●										●		●			
Body Floats			●															
Buoyancy Tanks			●															
Brackets and Bolts			●															
Gaskets and Bolts			•										•		•			
MOORING SYSTEM DURING OFFLOADING																		
Hawser External Structures	●	●				●												
Pickup Rope	●	●				●												
Floats (Pickup Rope and Hawsers)	●	●				●												
Chafing Chain (Through Fairlead and Ship Deck)	●	●				●												
Buoy Chain	●	●				●												
Chain Support Buoy and Connection Linkage	●	●				●												
Mooring System Connections	●	●				●												
MOORING SYSTEM NOT DURING OFFLOADING																		
Hawser External Structure	●					●												
Pickup Rope	●					●												
Floats (Pickup Rope, Hawsers)	●					●												
Chafing Chain	●					●												
Buoy Chain	•					●												
Chain Support Buoy and Connection Linkage	●					●												
SHIPBOARD CONNECTIONS		●													●			
Ship Manifold Expansion Joint		●											•		●			
Ship Manifold		●											•		●			
Gasket Between Hose Flange and Manifold		●													●			
Ship Manifold Valve		●													●			
Drip Tank		●													●			
Scuppers		●																

INSPECTION METHODS — 4 CORROSION; 5 NON-DESTRUCTIVE TESTING

OTS COMPONENTS	Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)	Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements
HOSE STRING NOT DURING OFFLOADING (Continued)																
Submarine Hose String		●		●												•
Submarine Hoses (Includes Nipples, Flanges, Seals, Bolts)		●		●		●	•	•	•	•	●	●	•		●	•
Flanges and Bolts		●		●		●	•	•	•	•	●		•		●	
Flange Seals															●	
Body Floats															●	
Buoyancy Tanks						●									●	
Brackets and Bolts		●		●		●		•	•	•	•		•		●	
Gaskets and Bolts																
MOORING SYSTEM DURING OFFLOADING																
Hawser External Structures																
Pickup Rope																
Floats (Pickup Rope and Hawsers)																
Chafing Chain (Through Fairlead and Ship Deck)																
Buoy Chain																
Chain Support Buoy and Connection Linkage																
Mooring System Connections																
MOORING SYSTEM NOT DURING OFFLOADING																
Hawser External Structure		●		●		●	●	•	•	•	•		•		●	●
Pickup Rope							●									
Floats (Pickup Rope, Hawsers)															●	
Chafing Chain		●		●		●	●	•	•	●	•		•	●		●
Buoy Chain		●		●		●	●	•	•	●	•		•	●		●
Chain Support Buoy and Connection Linkage		●		●		●	●	•	•	•	•		•	•	●	
SHIPBOARD CONNECTIONS																
Ship Manifold Expansion Joint		●			•	●	●	●	●	•	•		•	●	●	
Ship Manifold		●			•	●	●	●	●	•	•		•	●	●	
Gasket Between Hose Flange and Manifold		●			•	●									●	
Ship Manifold Valve		●			•	●									●	
Drip Tank		●													●	
Scuppers																

INSPECTION METHODS — 6 SURVEY; 7 OTS CONTROL; 8 SPECIAL METHODS; 9 MFG-MISC

OTS COMPONENTS	Sonar (Bare-Surface, Overburden)	Surveying-Component Location	Scour	Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gauge (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off	Procedure-Water Left in Hose String
HOSE STRING NOT DURING OFFLOADING (Continued)																						
Submarine Hose String				●	•	●	●	●			•	•	●						●		●	●
Submarine Hoses (Includes Nipples, Flanges, Seals, Bolts)							●	●			•	•	●		●		●		●		●	●
Flanges and Bolts							•	•									●					●
Flange Seals							•	•									●					●
Body Floats																						
Buoyancy Tanks																						
Brackets and Bolts																						
Gaskets and Bolts							•	•									•					
MOORING SYSTEM DURING OFFLOADING								●		●											●	
Hawser External Structures								●		●											●	
Pickup Rope																						
Floats (Pickup Rope and Hawsers)																						
Chafing Chain (Through Fairlead and Ship Deck)								●		●											●	
Buoy Chain								●		●											●	
Chain Support Buoy and Connection Linkage																						
Mooring System Connections																						
MOORING SYSTEM NOT DURING OFFLOADING																						
Hawser External Structure								●		●						●						
Pickup Rope																						
Floats (Pickup Rope, Hawsers)																						
Chafing Chain								●		•						●						
Buoy Chain								●		•						●						
Chain Support Buoy and Connection Linkage																						
SHIPBOARD CONNECTIONS																						
Ship Manifold Expansion Joint							•										●					
Ship Manifold							•										●					
Gasket Between Hose Flange and Manifold							•										●					
Ship Manifold Valve							•												●	●		
Drip Tank																		•				
Scuppers																						

NOTE:

1. Legend - • Potential Method; C Potential Method CALM ONLY; p Potential Method for Inspection of Part of Component; ● Method Selected for Cost-Effective Analysis in Section 4.4

2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

3-20 95% (62)

TABLE 3-3 UNDERSEA PIPELINE

INSPECTION METHODS

OTS COMPONENTS	1 VISUAL: Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	2 OIL SPILL DETECTOR: Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	3 DYNAMIC INSERTIONS INTO OTS: Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic	4 CORROSION: Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)
UNDERSEA PIPELINES																						
Pipeline			●			•						●	●	●	●	●		•	●			●
Pipe			●		•	•						●	●	●	●	●		•	●	●	•	●
Corrosion			●		•							•	•	●	●				●	●	•	●
Defective Weld			●									•	•	●	●			•				
Rupture Damage, Other			●									●	●	●	●	●		•	•			
Cathodic Protection			●																	●		●

OTS COMPONENTS	5 NON-DESTRUCTIVE TESTING: Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements	6 SURVEY: Sonar (Bare-Surface, Overburden)	Surveying (Component Location, Mapping)	Scour	7 OTS CONTROL: Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)
UNDERSEA PIPELINES																		
Pipeline											●		●	●	●	●	●	●
Pipe	[illegible]	[illegible]	•	●	●	●	●	●	•		●		●	●	●			
Corrosion	[illegible]	●	•	●	●	●	●	●	•									
Defective Weld	●	●	•	●	●	●	●	●	•									
Rupture Damage, Other	●	●	•	●							•		●	●	•	●	●	●
Cathodic Protection											•							

OTS COMPONENTS	8 SPECIAL METHODS: Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	9 MFG - MISC: Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off	Hydrocarbon Probe
UNDERSEA PIPELINES																
Pipeline	●	●			•	•	●	•			•					●
Pipe	●	●			•	•	●	•			•					●
Corrosion	●	•									●					●
Defective Weld	●	●									●					●
Rupture Damage, Other	●	●			•	•	●	•			•					●
Cathodic Protection													●			

NOTE:

1. Legend - • Potential Method; ● Method Selected for Cost-Effective Analysis in Sect. 4.4
2. **Methods Shown for Major Components** (i.e. **Floating** Hose String) Provide Inspection for the Component As a Whole

3-21

95%

63

such as the type and size of pipeline, pipeline location, pipeline depth below the surface, environmental conditions, pipeline age and the type of oil transported in the pipeline. The inspection methods given in Table 3-2 may be extremely beneficial for some pipelines but not for others. Older pipelines may require more inspections for corrosion while newer pipelines may require inspections of welds or more frequent inspections of potential bare spots, overburden or mapping of the pipeline.

3.4 SALM-SPM INSPECTION METHODS

Potential inspection methods for the major OTS components of a hypothetical SALM single point mooring system are given in Table 3-4. The major OTS components include the mooring buoy, fluid swivel, hose arm, riser shaft, pipeline and manifold (PLEM) and mooring base. Figures 3-1 and 3-3 show the general arrangement of the SALM. A typical fluid swivel assembly is given in Figure 3-4.

3.5 CALM-SPM INSPECTION METHODS

Potential inspection methods for the major OTS components of a hypothetical CALM single point mooring system are given in Table 3-5. The major OTS components include the mooring buoy, underbuoy hose string, PLEM, PLEM anchor base and chain anchor. Figure 3-2 shows the general arrangement of the CALM. The general arrangement of the buoy is shown in Figure 3-5. A typical product distribution unit is shown in Figure 3-6 and the PLEM is shown in Figure 3-7.

TABLE 3-4 SPM-SALM INSPECTION METHODS

OTS COMPONENTS	1 VISUAL							2 OIL SPILL DETECTOR					3 DYNAMIC INSERTIONS INTO OTS						4 CORROSION			
INSPECTION METHODS	Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic	Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)
MOORING BUOY	◉																					
External Structure	●		◉	●		•																
Navigation Light	●			●		•																
Hull	●		◉			•														◉		●
Fenders	●		◉			•														◉		●
Buoy Anodes	•		◉			•														◉		●
Mooring Bracket	●			●		•														◉		●
Center Shaft Externsion			◉																	◉		●
Buoy Universal Joint			◉																	◉		●
Anchor Chain Attachment Bracket			◉	◉		•														◉		●
Anchor Chain			◉	●		•														◉		●
Chain Swivel			◉																	◉		●
Shaft Universal Joint			◉																	◉		●
Connector-Universal Joint to Fluid Swivel			◉																	◉		●
Bolts			◉																	◉		●
Internal Structure																						
Buoy Body Compartments				◉																◉		
Air Vent Plugs				◉																◉		
Flooding Valves				◉																◉		
Piping Hull Penetrators				◉																◉		
Sump Pump				◉																◉		
Buffers				◉																◉		
Manhole Covers				◉																◉		
Pins				◉																◉		
Fog Signal	•			◉																◉		
Bolts				◉																◉		
Brackets				◉																◉		
MOORING LINE (SEE TABLE 3-2)																						
FLUID SWIVEL ASSEMBLY				◉	●			•	•		•	•	◉		◉					◉		
Attachment Eye				◉																◉		
Housing				◉									◉		◉					◉		
Split Clamp Ring				◉									◉		◉					◉		
Joints				◉									◉		◉					◉		
Gaskets				◉									◉		◉					◉		
Seals				◉									◉		◉					◉		
Bearings				◉									◉		◉					◉		
Brackets				◉									◉		◉					◉		
Bolts				◉									◉		◉					◉		

OTS COMPONENTS	5 NON-DESTRUCTIVE TESTING												6 SURVEY			7 OTS CONTROL		
INSPECTION METHODS	Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements	Sonar (Bare-Surface, Overburden)	Surveying (Component Location, Mapping)	Scour	Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)
MOORING BUOY														◉				
External Structure																		
Navigation Light											●							
Hull		●	●	●	•	•	●	•	•	•	◉							
Fenders		●	•	•	•	•	•	•	•		●							
Buoy Anodes		●	•	•	•	•	•	•	•		●	●						
Mooring Bracket		●	•	•	•	•	•	•	•		●							
Center Shaft Externsion		●	•	•	•	•	•	•	•		●							
Buoy Universal Joint		●	●	●	•	●	●	•	•		●							
Anchor Chain Attachment Bracket		●	●	●	•	●	●	•	•		●							
Anchor Chain		●	●	●	●	●	●	•	•		●	●						
Chain Swivel		●	●	●	•	●	●	•	•		●							
Shaft Universal Joint		●	●	●	•	●	●	•	•		●							
Connector-Universal Joint to Fluid Swivel		●	●	●	•	●	●	•	•		●							
Bolts		●	•	•	•	•	•	•	•		●							
Internal Structure																		
Buoy Body Compartments		●	•	•	•	•	•	•	•	•	●							
Air Vent Plugs		●	•	•	•	•	•	•	•	•	●							
Flooding Valves		●	•	•	•	•	•	•	•	•	●							
Piping Hull Penetrators		●	•	•	•	•	•	•	•	•	●							
Sump Pump		●	•	•	•	•	•	•	•	•	●							
Buffers		●	•	•	•	•	•	•	•	•	●							
Manhole Covers		●	•	•	•	•	•	•	•	•	●							
Pins		●	•	•	•	•	•	•	•	•	●							
Fog Signal											●							
Bolts		●	•	•	•	•	•	•	•	•	●							
Brackets		●	•	•	•	•	•	•	•	•	●							
MOORING LINE (SEE TABLE 3-2)																		
FLUID SWIVEL ASSEMBLY																		
Attachment Eye		●	●	●	●	●	●	•	•			●						
Housing		●	•	●	•	•	●	•	•		●							
Split Clamp Ring		●	•	•	●	●	•	•	•		●							
Joints	●	●	•	•	•	●	●	•	•		●							
Gaskets	●	•	•	•				•			●							
Seals	●	●	•	•	•	•	•	•			●							
Bearings	◉	●	●	●				•			●							
Brackets		●	•	•	•	•	●	•	•		●							
Bolts		●	•	•	•	•	●	•	•		●							

OTS COMPONENTS	8 SPECIAL METHODS												9 MFG - MISC		
INSPECTION METHODS	Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off
MOORING BUOY															
External Structure		•													
Navigation Light															
Hull															
Fenders															
Buoy Anodes													◉		
Mooring Bracket		●		•											
Center Shaft Externsion		●		•											
Buoy Universal Joint		●		•											
Anchor Chain Attachment Bracket		●		•											
Anchor Chain		●		•											
Chain Swivel		●		•										◉	
Shaft Universal Joint		●		•											
Connector-Universal Joint to Fluid Swivel		●		•											
Bolts															
Internal Structure															
Buoy Body Compartments															
Air Vent Plugs															
Flooding Valves													◉	◉	
Piping Hull Penetrators															
Sump Pump													◉	◉	
Buffers															
Manhole Covers															
Pins															
Fog Signal													◉	◉	
Bolts															
Brackets															
MOORING LINE (SEE TABLE 3-2)															
FLUID SWIVEL ASSEMBLY	◉	◉					●						◉	◉	
Attachment Eye		●													
Housing											•			◉	
Split Clamp Ring															
Joints											●				
Gaskets											●				
Seals											●				
Bearings	●	◉													
Brackets															
Bolts															

NOTE:

1. Legend - • Potential Method; ◉ Method Selected for Cost-Effective Analysis in Sect. 4.4.

2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

95%

65

TABLE 3-4 (CONTINUED)

INSPECTION METHODS (columns) / OTS COMPONENTS (rows)

OTS COMPONENTS	1 VISUAL							2 OIL SPILL DETECTOR					3 DYNAMIC INSERTIONS INTO OTS					
	Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic
HOSE ARM																		
Hose Arm Assembly			●		•							•	●		●			•
Piping			●		•								●		●			•
Bolts			●															
Valve			●										●		●			
Hose Connections			●		•								●		●			•
Bolts			●															
Flanges			●										●		●			•
Gaskets			●										●		●			•
Hose			●		•													
Buoyancy Tanks			●															
Resilient Bumpers-Under Buoyancy Tanks			●															
Brackets			●															
Bolts			●															
HOSE STRING (SEE TABLE 3-2)																		
RISER SHAFT					•													
Housing			●		•													
Bumper Rail			●															
Product Transfer Pipe			●										●		●			
Bolts			●															
Brackets			●															
PLEM																		
Piping			●		●								●		●			•
Base Hose			●		●								●		●			•
Flanges			●										●		●			•
Gaskets			●										●		●			•
Chamber			●		●								●		●			
Check Valves			●										●		●			
Ball Valves			●										●		●			
Isolation Valve			●										●		●			
Bolts			●															
Brackets			●															
MOORING BASE																		
External Structure			●															
Bumper Rail			●															
Siltation Level			●															
Piles			●															
Anodes			●															
Scour Protection			●															
Bolts			●															
Brackets			●															

OTS COMPONENTS	4 CORROSION				5 NON-DESTRUCTIVE TESTING											
	Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)	Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements
HOSE ARM																
Hose Arm Assembly		●		●												
Piping		●		●	●	●	•	●	•	•	●	●	•		●	
Bolts		●		●												
Valve		●		●	●	●	•	•	•	•	•	•	•		●	
Hose Connections		●		●	●	●	•	•	•	•	•	•	•		●	
Bolts		●		●											●	
Flanges		●		●	●			•	•	•	•	•	•		●	
Gaskets		●			●										●	
Hose		●		●	●		•	•				•			●	
Buoyancy Tanks		●		●		●	•								●	
Resilient Bumpers-Under Buoyancy Tanks		●													●	
Brackets		●		●					•	•	•				●	
Bolts		●		●											●	
HOSE STRING (SEE TABLE 3-2)																
RISER SHAFT		●		●												
Housing		●		●		●	•	•	•	•	●	•	•		●	
Bumper Rail		●		●	●			•							●	
Product Transfer Pipe		●		●		●	●	●	•	•	●	●	•		●	
Bolts		●		●											●	
Brackets		●		●											●	
PLEM		●		●												
Piping		●		●	●	●	•	●	•	•	●	●	•		●	
Base Hose		●		●	●	●	•	•				•			●	
Flanges		●		●	●	●	•	•	•	•	●	•	•		●	
Gaskets		●			●										●	
Chamber		●		●	●		•	●	•	•	●	●	•		●	
Check Valves		●		●	●		•	•	•	•	●	●	•		●	
Ball Valves		●		●	●		•	•	•	•	●	•	•		●	
Isolation Valve		●		●	●		•	•	•	•	●	•	•		●	
Bolts		●		●					•	•	●		•		●	
Brackets		●		●					•	•	●		•		●	
MOORING BASE		•		●												
External Structure		●		●		●		●	•	•	●		•		●	
Bumper Rail		●		●		•		•			•		•		●	
Siltation Level						•										
Piles		●		●				•			•		•		●	
Anodes		●		●		•		•			•		•		●	●
Scour Protection		●		●		•		•			•		•		●	
Bolts		●		●		•		•			•		•		●	
Brackets		●		●		•		•	•	•	•	•	•		●	

OTS COMPONENTS	6 SURVEY			7 OTS CONTROL			8 SPECIAL METHODS												9 MFG - MISC		
	Sonar (Bare-Surface, Overburden)	Surveying (Component Location, Mapping)	Scour	Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off
HOSE ARM																					
Hose Arm Assembly													●						●	●	
Piping							●	●					•								
Bolts																					
Valve							•	•											●	●	
Hose Connections							●	●									•				
Bolts																					
Flanges																	•				
Gaskets							•										•				
Hose							●	●						•	●						
Buoyancy Tanks																					
Resilient Bumpers-Under Buoyancy Tanks																					
Brackets																					
Bolts																					
HOSE STRING (SEE TABLE 3-2)																					
RISER SHAFT																					
Housing													●								
Bumper Rail							•														
Product Transfer Pipe							●	●						●			•				
Bolts																					
Brackets																					
PLEM													●								
Piping							●	●						•			●				
Base Hose							●	●							•		●				
Flanges							•	•									●				
Gaskets							•	•									●				
Chamber							•	•									●		●	●	
Check Valves							•	•											●	●	
Ball Valves							•	•											●	●	
Isolation Valve							•	•													
Bolts																					
Brackets																					
MOORING BASE		●	●																		
External Structure																					
Bumper Rail																					
Siltation Level																				●	
Piles																					
Anodes																			●		
Scour Protection			●																●		
Bolts																					
Brackets																					

NOTE:

1. Legend - • Potential Method; ● Method Selected for Cost-Effective Analysis in Section 4.4
2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

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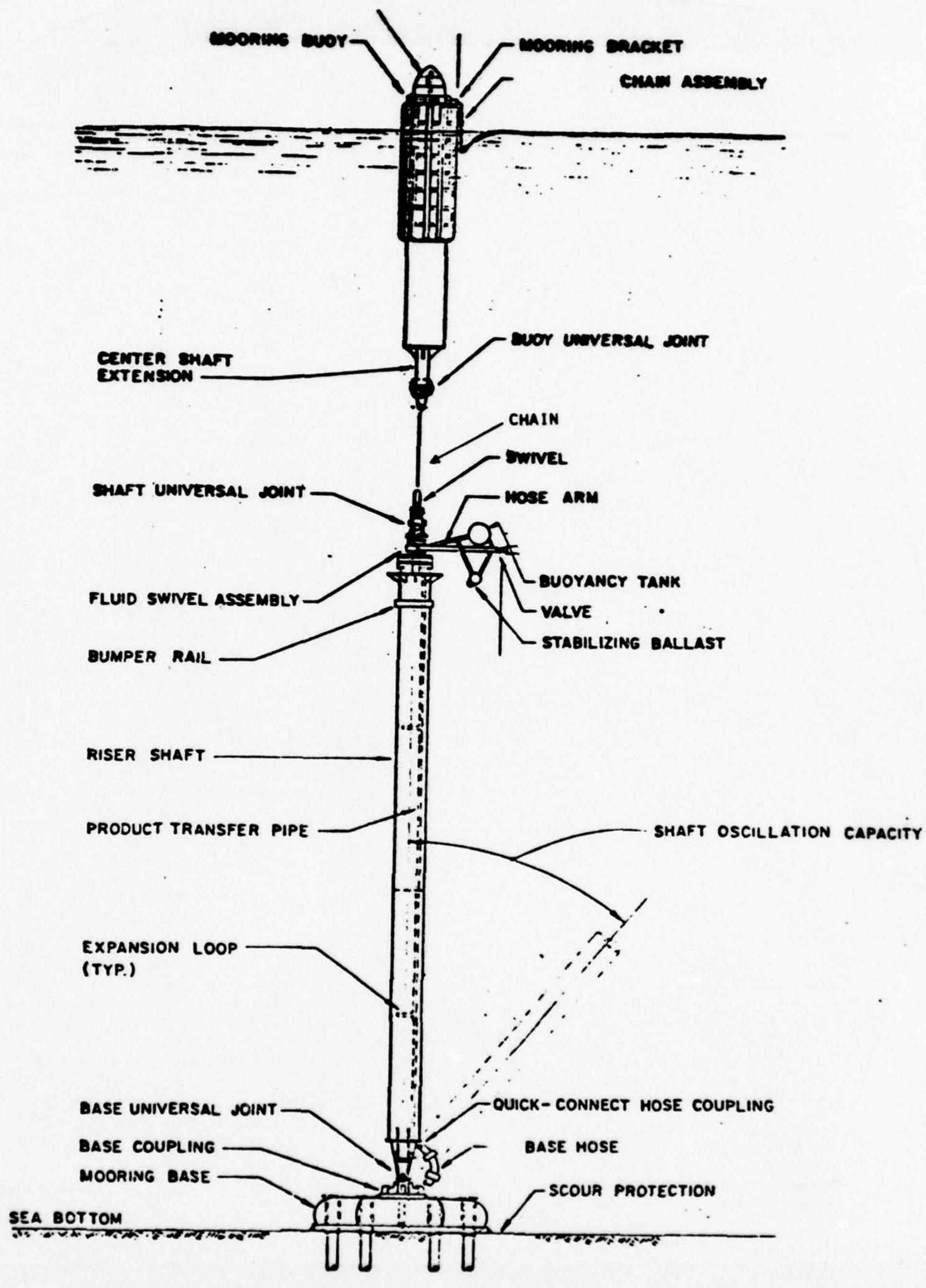
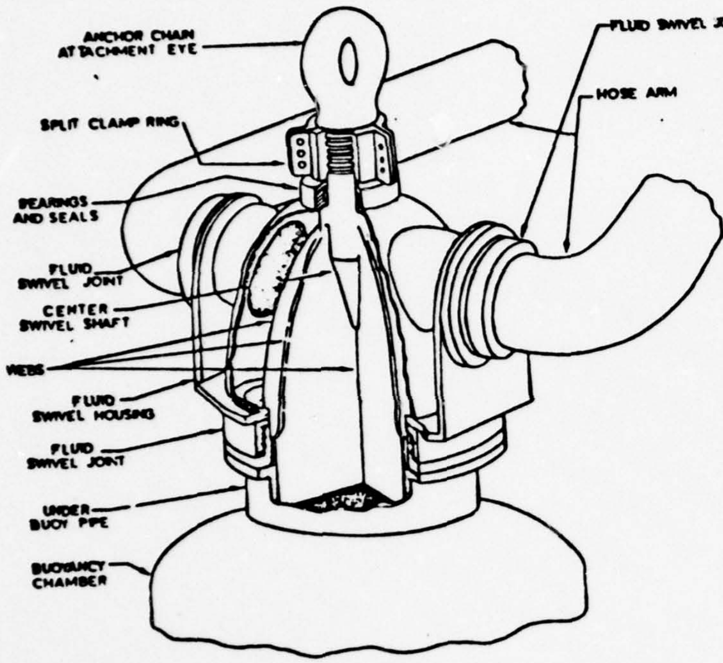
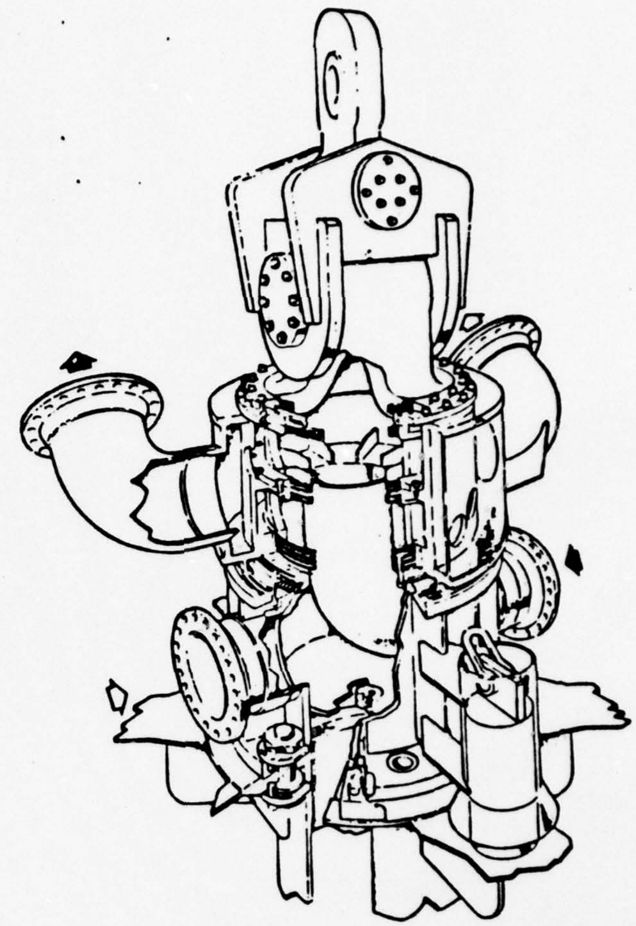


FIGURE 3-3 GENERAL ARRANGEMENT OF SALM



Source: EXXON Research and Engineering Co.



Source: Single Buoy Moorings of America, Inc.

FIGURE 3-4 FLUID SWIVEL ASSEMBLIES FOR A SINGLE ANCHOR LEG MOORING, CUT-AWAY VIEW

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TABLE 3-5 SPM-CALM INSPECTION METHODS

OTS COMPONENTS / INSPECTION METHODS	1 VISUAL							2 OIL SPILL DETECTOR					3 DYNAMIC INSERTIONS INTO OTS					
	Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic
MOORING BUOY																		
External Structure																		
Navigation Light	●	●		●		•												
Fog Signal	•			●														
Hull	●			●		•												
Fenders	•		●	●		•												
Buoy Anodes			●															
Mooring Bracket	●		●	●		•												
Anchor Chains	●		●	●		•												
Hoisting Equipment	•			●		•												
Winch	•			●		•												
Internal Structure																		
Product Distribution Unit (Fluid Swivel)				●									●		●			
Top Cover				●									●		•			
Upper and Lower Shell (Rotating)				●									•		•			
Shell Supports				●														
Fixed Assemblies				●														
Brackets				●														
Bearings				●														
Seals				●									●		●			
Gaskets				●									●		●			
Flanges				●									●		●			
Piping				●									●		●			
Bolts				●									●		●			
Flanges				●									●		●			
Seals				●									●		●			
Gaskets				●									●		●			
Piping				●									●		●			
Valves				●									●		●			
Rotating Deck				●														
Turntable Roller Bearings				●														
Brackets				●														
Power Supply				●														
Fog Signal				●														
Pumps				●														
Motors				●														
Bolts				●														
Misc. Electrical Equipment				●														

OTS COMPONENTS / INSPECTION METHODS	4 CORROSION				5 NON-DESTRUCTIVE TESTING											
	Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)	Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3 Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements
MOORING BUOY																
External Structure																
Navigation Light		●													●	
Fog Signal		●													●	
Hull		●		●		●	●	●	•	•	●	•	•	•	●	
Fenders		●		●		●	•	•	•	•	•	•	•		●	
Buoy Anodes		●		●		●	•	•	•	•	•	•	•		●	•
Mooring Bracket		●		●		●	•	•	•	•	•	•	•		●	
Anchor Chains		●		●		●	●	●	●	●	●	•	●	●	●	●
Hoisting Equipment		●													●	
Winch		●													●	
Internal Structure																
Product Distribution Unit (Fluid Swivel)		●													●	
Top Cover		●		•		●	•	●	●	•	•	•	●	•	●	
Upper and Lower Shell (Rotating)		●		•		●	•	●	●	•	•	•	•	•	●	
Shell Supports		●				●	•	●	●	•	•		•	●	●	
Fixed Assemblies		●				●	•	●	●	•	•		•	●	●	
Brackets		●				●	•	●	●	•	•		•	●	●	
Bearings		●			●	●	●	●				•			●	
Seals		●			●	●	•	•	•	•	•	•	•		●	
Gaskets		●			●	•	•	•				•			●	
Flanges		●			●	•	●	•	●	•	•	•	•	•	●	
Piping		●			●	●	●	●	●	•	•	•	•	●	●	
Bolts		●				●	•	•	●	•	•	•	•		●	
Flanges		●			●	●	•	●	●	•	•	•	•	●	●	
Seals		●			●	●	•	•	•	•	•		•	•	●	
Gaskets		●			●	●	•	•				•			●	
Piping		●			●	●	●	●	●	•	•		•	●	●	
Valves		●			•	●	•	•	●	•	•		•	●	●	
Rotating Deck		●				●	•	●	●	•			•	●	●	
Turntable Roller Bearings		●													●	
Brackets		●													●	
Power Supply		●													●	
Fog Signal		●													●	
Pumps		●													●	
Motors		●													●	
Bolts		●													●	
Misc. Electrical Equipment		●													●	

OTS COMPONENTS / INSPECTION METHODS	6 SURVEY			7 OTS CONTROL			8 SPECIAL METHODS												9 MFG - MISC		
	Sonar (Bare-Surface, Overburden)	Surveying (Component Location, Mapping)	Scour	Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off
MOORING BUOY		●																			
External Structure																					
Navigation Light																					
Fog Signal																					
Hull																					
Fenders																					
Buoy Anodes																			●		
Mooring Bracket								●		•											
Anchor Chains								•		•											
Hoisting Equipment																			●	●	
Winch																			●	●	
Internal Structure																					
Product Distribution Unit (Fluid Swivel)																			●	●	
Top Cover																					
Upper and Lower Shell (Rotating)																			•	•	
Shell Supports																					
Fixed Assemblies																					
Brackets																					
Bearings								•	•												
Seals							•	•									●				
Gaskets							•	•									●				
Flanges							•	•													
Piping							•	•													
Bolts																					
Flanges							•	•									●				
Seals							•	•									●				
Gaskets							•	•									●				
Piping							•	•									●				
Valves																			●	●	
Rotating Deck																			●	●	
Turntable Roller Bearings																			●	●	
Brackets																					
Power Supply																			●	●	
Fog Signal																			●	●	
Pumps																			●	●	
Motors																			●	●	
Bolts																					
Misc. Electrical Equipment																			●	●	

NOTE:

1. Legend - • Potential Method; ● Method Selected for Cost-Effective Analysis in Section 4.4

2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

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TABLE 3-5 (CONTINUED)

OTS COMPONENTS / INSPECTION METHODS	1 VISUAL							2 OIL SPILL DETECTOR					3 DYNAMIC INSERTIONS INTO OTS						4 CORRO-SION			
	Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic	Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont., Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)
HOSE ARM (SEE TABLE 3-4)																						
HOSE STRING (SEE TABLE 3-2)																						
UNDERBUOY HOSE STRING (SEE TABLE 3-2 and TABLE 4-2)																						
Hoses (Includes Nipples and Flanges)																						
Flanges																						
Seals																						
Buoyancy Tanks																						
Spreader Bars																						
Gaskets																						
Bolts																						
Brackets																						
PLEM (SEE TABLE 3-4)																						
PLEM ANCHOR BASE			●																	●		●
Base Assembly			●																	●		●
Piles			●																	●		●
Brackets			●																	●		●
Bolts			●																	●		●
Gaskets			●																	●		●
Flanges			●																	●		●
Anodes			●																	●		●
Scour Protection			●																	●		●
CHAIN ANCHOR			●																	●		●
Anodes			●																	●		●

OTS COMPONENTS / INSPECTION METHODS	5 NON-DESTRUCTIVE TESTING												6 SURVEY		
	Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements	Sonar (Bare-Surface, Overburden)	Surveying (Component Location, Mapping)	Scour
HOSE ARM (SEE TABLE 3-4)															
HOSE STRING (SEE TABLE 3-2)															
UNDERBUOY HOSE STRING (SEE TABLE 3-2 and TABLE 4-2)															
Hoses (Includes Nipples and Flanges)															
Flanges															
Seals															
Buoyancy Tanks															
Spreader Bars															
Gaskets															
Bolts															
Brackets															
PLEM (SEE TABLE 3-4)															
PLEM ANCHOR BASE														●	●
Base Assembly		●		●	•	•	●		•		●				
Piles		•		•			•		•		●				
Brackets		•		•			•		•		●				
Bolts		•		•			•		•		●				
Gaskets		•		•			•				●				
Flanges		•		•			•		•		●				
Anodes		•		•			•		•		●	●			
Scour Protection		•		•			•		•		●				●
CHAIN ANCHOR		●		●	•	•	●		•		●	●			
Anodes		•		•			•				●	●			

OTS COMPONENTS / INSPECTION METHODS	7 OTS CON-TROL			8 SPECIAL METHODS												9 MFG - MISC			
	Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off	Magnetic Chip Detectors
HOSE ARM (SEE TABLE 3-4)																			
HOSE STRING (SEE TABLE 3-2)																			
UNDERBUOY HOSE STRING (SEE TABLE 3-2 and TABLE 4-2)																			
Hoses (Includes Nipples and Flanges)																			
Flanges																			
Seals																			
Buoyancy Tanks																			
Spreader Bars																			
Gaskets																			
Bolts																			
Brackets																			
PLEM (SEE TABLE 3-4)																			
PLEM ANCHOR BASE																			
Base Assembly																			
Piles																			
Brackets																			
Bolts																			
Gaskets																			
Flanges																			
Anodes																			
Scour Protection																●			
CHAIN ANCHOR																			
Anodes																●			

NOTE:

1. Legend - • Potential Method; ●Method Selected for Cost-Effective Analysis in Section 4.4

2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

(70)

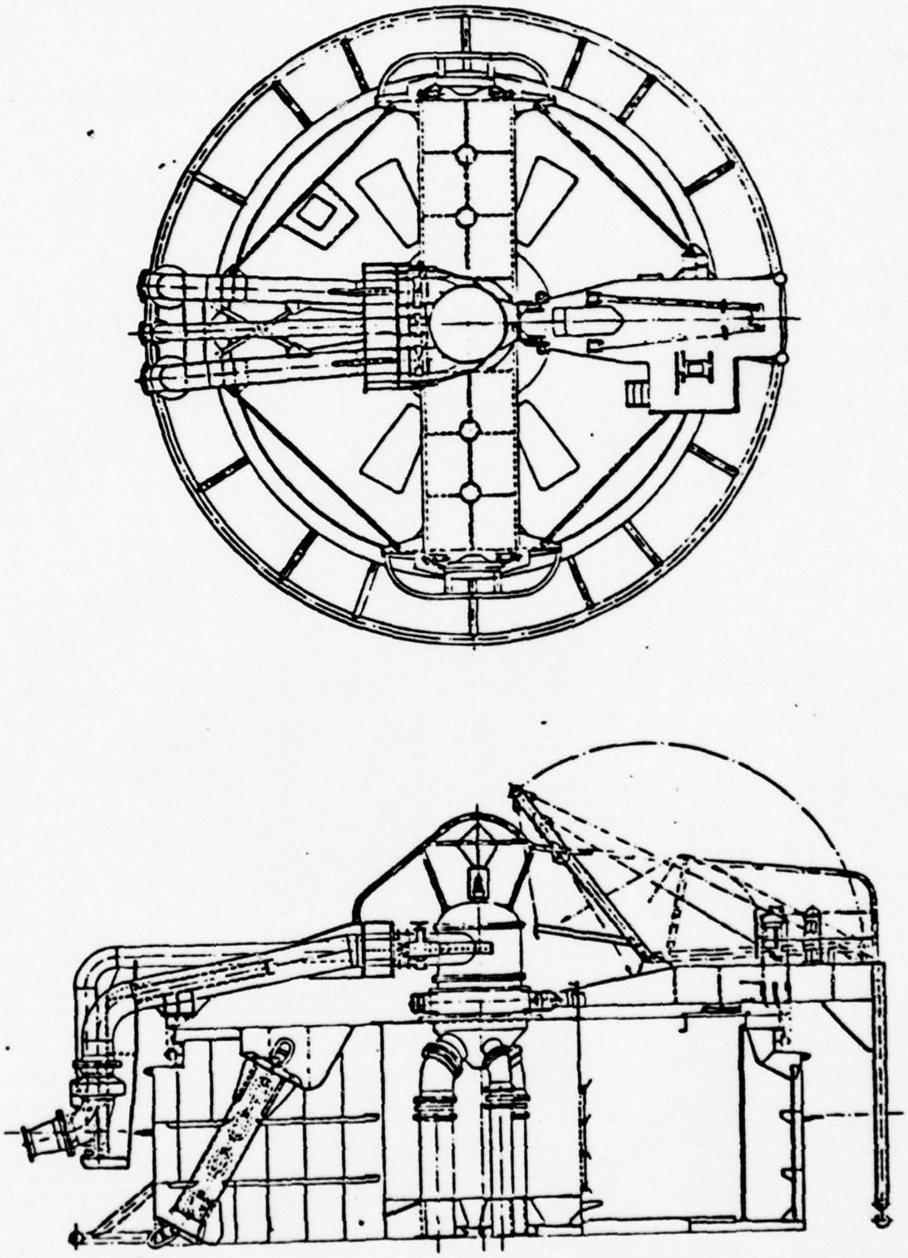

FIGURE 3-5 GENERAL ARRANGEMENT OF A SURFACE BUOY FOR CATENARY ANCHOR LEG MOORING

SOURCE: IMODCO, EUROPE, INC.

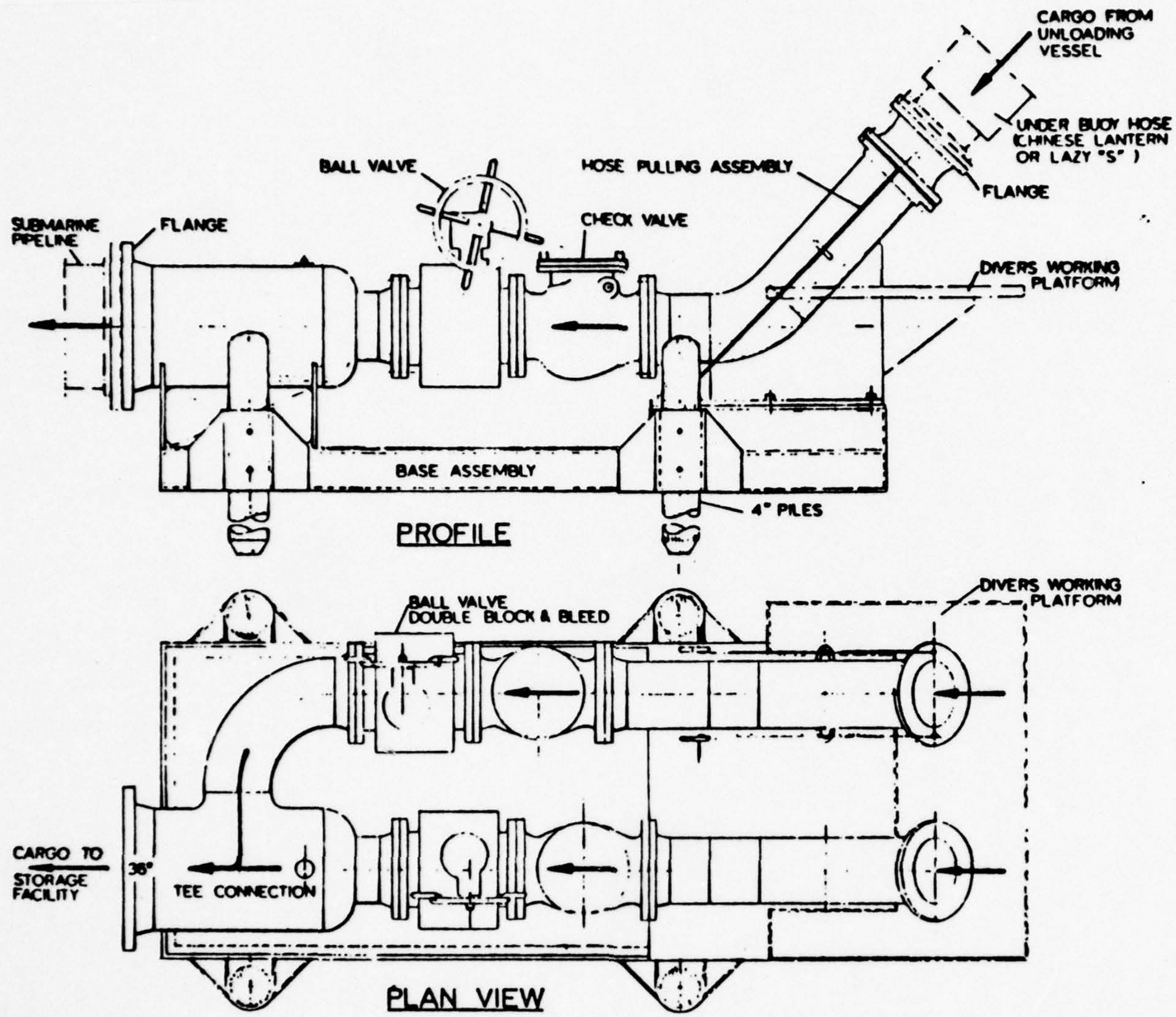

FIGURE 3-7 PIPELINE END MANIFOLD

SOURCE: IMODCO, EUROPE, INC.

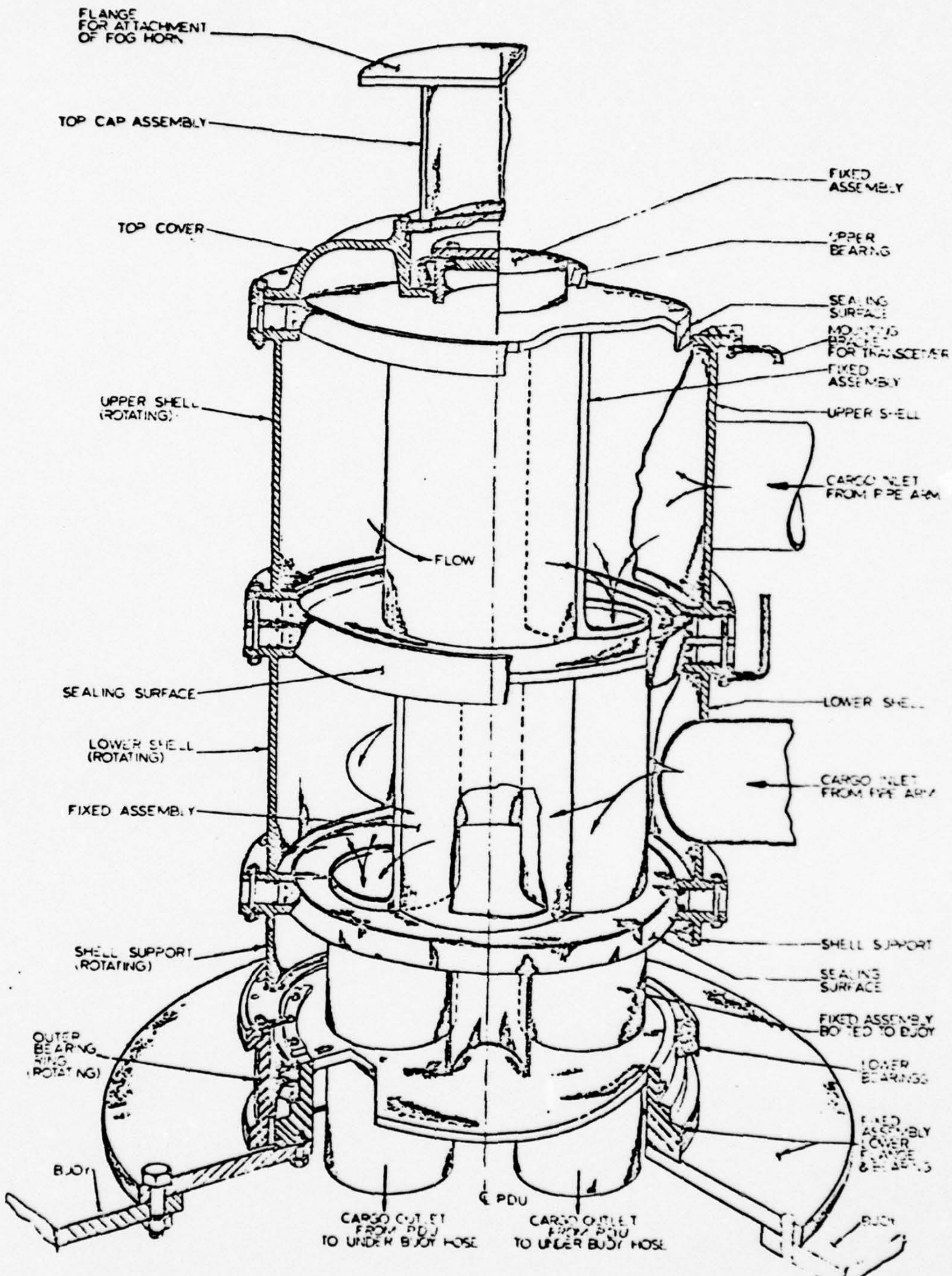

FIGURE 3-6 A PRODUCT DISTRIBUTION UNIT (PDU) FOR A CATENARY ANCHOR LEG MOORING

SOURCE: IMODCO, EUROPE, INC.

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3.6 OFFSHORE PLATFORM AND THE PUMPING AND METERING SYSTEMS

Potential inspection methods for the major OTS components of the offshore platform and the pumping and metering systems are given in Table 3-6. The major OTS components include the platform support, ship navigational aid, fire protection system, waste disposal system (see Figure 3-8), components upstream from the pumps, pump section and components downstream from the pumps, as shown in Figure 3-9.

TABLE 3-6 OFFSHORE PLATFORM AND THE PUMPING AND METERING SYSTEMS-INSPECTION METHODS

INSPECTION METHODS / OTS COMPONENTS	1 VISUAL							2 OIL SPILL DETECTOR					3 DYNAMIC INSERTIONS INTO OTS						4 CORROSION				5 NON-DESTRUCTIVE TESTING												6 SURVEY			7 OTS CONTROL			8 SPECIAL METHODS												9 MFG - MISC			
	Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic	Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)	Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements	Sonar (Bare-Surface, Overburden)	Surveying (Component Location, Mapping)	Scour	Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged Load Monitor	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off	Magnetic Chip Detectors
PUMPING PLATFORM																																																								
Platform Support	●		●																	●		●		●	●	●	•	•	●	●	•		●			•	●					●		●									●	●		
Earthquake Structural Damage	●		●			•														●		●		●	●	●	•	•	●	●	•		●			•	●					●		●												
Ship Navigational Aid				●																																																	●	●		
Visual				●																																																				
Radar				●																●													●																				●	●	●	
Laser (Not in General Use)				●																●													●																				●	●	●	
Sonar				●																●													●																				●	●	●	
Microwave				●																●													●																				●	●	●	
Fog Horn				●																●													●																				●	●	●	
Lights				●																●													●																				●	●	●	
Fire Protection System				●																●																																	●	●	●	
Gas Detectors				●																●																																	●	●	●	
Fire Detectors				●																●																																	●	●	●	
Oil Spill Detectors				●						•		•								●																																	●	●	●	
Sprinklers				●																●																																	●	●	●	
Fire Water Pump Station				●																●																																	●	●		
Pumps				●																●																																	●	●		
Foam				●																																																	●	●		
Fire Extinguisher				●																●																																	●	●		
Waste Disposal System				●		•				●		●																																												
Hole in Deck				●		•				●		●								●				●	●	•	•	•		•	•	●									●															
Waste Disposal System-Tank				●		•							●		●					●				●	●	•	•	•		•	•	•	•								●	●													●	
-Piping				●		•							●		●			•		●				●	●	•	•	•		•	•	•	•								●	●									•					
-Valve				●		•							●		●					●			•	•	•	•	•	•		•	•	•	•								●	●	•								•		●	●	●	
Sea Sump				●		•														●				•	•	•	•	•		•	•	•	•																							
M.O. Tank Pump				●		•														●			•	●	•	•	•	•		•	•	•	•									•	•										●	●	●	●
Air Eliminator Drain Pipe Valve				●		•														●			•	●	●	•	•	•		•	•	•	•								•	•											●	●	●	
Reclaimed Oil Tank Valve				●		•																	•	●	●	•	•	•		•	•	•	•																				●	●	●	
Oily Water Sump				●		•														●				●	●	•	•	•		•	•	•	•								●	●														
Sea Sump				●		•														●				●	●	•	•	•		•	•	•	•								●	●														
Bolts				●																●				•	•	•	•	•		•	•	•	●									•														
Flanges				●																●				•	•	•	•	•		•	•	•	●								•	•														

NOTE:

1. Legend - • Potential Method; ● Method Selected for Cost-Effective Analysis in Section 4.4

2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

TABLE 3-6 (CONTINUED)

INSPECTION METHODS – Groups 1–4

OTS COMPONENTS	1 VISUAL: Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	2 OIL SPILL DETECTOR: Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	3 DYNAMIC INSERTIONS INTO OTS: Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic	4 CORROSION: Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)
Upstream From Pumps																						
Upstream-Piping				●									●		•					●		
-Flange				●									●		●					●		
Sampler-Drain Valve (Left Open)				●									●		●					●		
-Container				●																●		
-Valve				●																●		
Strainer-Drain Valve (Left Open)				●																●		
-Basket				●																●		
Air Eliminator-Drain Valve (Left Open)				●																●		
-Chamber				●																●		
-High Level Switch				●																●		
Bolts				●																●		
Flanges				●																●		
Pump Section																						
Piping				●									●		●					●		
Pump-Valve				●									●		●					●		
-MOV				●									●		●					●		
-Seals				●																●		
Bolts				●																●		
Flanges				●																●		
Downstream From Pumps																						
Meter Run-Valve				●									●		●					●		
-Control Valve				●									●		●					●		
-Straightener				●									●		●					●		
-Turbine Flow Meter				●																●		
-Flange				●									●		●					●		
Meter Prover-Valve				●									●		●					●		
-Diverter Valve				●									●		●					●		
-Drain				●									●		●					●		
-Line				●									●		●					●		
Launcher-Valve				●									●		●					●		
-Container				●									●		●					●		
-Drain Valve (Left Open)				●									●		●					●		
-Gaskets				●									●		●					●		
Flanges				●																●		
Bolts				●																●		
Piping				●									●		●					●		
Brackets				●																●		

INSPECTION METHODS – Group 5

OTS COMPONENTS	5 NON-DESTRUCTIVE TESTING: Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements
Upstream From Pumps												
Upstream-Piping		●	●	•	•	•		•	•	•	●	
-Flange		●	●	•	•	•		•	•	•	●	
Sampler-Drain Valve (Left Open)		●	●	•	•	•		•	•	•	●	
-Container		●	●	•	•	•		•	•	•	●	
-Valve	•	●	●	•	•	•		•	•	•	•	
Strainer-Drain Valve (Left Open)		●	●	•	•	•		•	•	•	●	
-Basket	•	●	●	•	•	•		•	•	•	●	
Air Eliminator-Drain Valve (Left Open)		●	●	•	•	•		•	•	•	●	
-Chamber		●	●	•	•	•		•	•	•	●	
-High Level Switch											●	
Bolts		•	•	•	•	•		•	•	•	●	
Flanges		•	•	•	•	•		•	•	•	●	
Pump Section												
Piping		●	●	•	•	•		•	•	•	●	
Pump-Valve	•	●	●	•	•	•		•	•	•	●	
-MOV		●	●	•	•	•		•	•	•	●	
-Seals		•	•	•	•	•		•	•	•	●	
Bolts		•	•	•	•	•		•	•	•	●	
Flanges		•	•	•	•	•		•	•	•	●	
Downstream From Pumps												
Meter Run-Valve	•	●	●	•	•	•		•	•	•	●	
-Control Valve	•	●	●	•	•	•		•	•	•	●	
-Straightener		●	●	•	•	•		•	•	•	●	
-Turbine Flow Meter		•	•	•	•	•		•	•	•	●	
-Flange		•	•	•	•	•		•	•	•	●	
Meter Prover-Valve		●	●	•	•	•		•	•	•	●	
-Diverter Valve	•	●	●	•	•	•		•	•	•	●	
-Drain	•	●	●	•	•	•		•	•	•	●	
-Line		●	●	•	•	•		•	•	•	●	
Launcher-Valve	•	●	●	•	•	•		•	•	•	●	
-Container		●	●	•	•	•		•	•	•	●	
-Drain Valve (Left Open)	•	•	•	•	•	•		•	•	•	●	
-Gaskets		•	•	•	•	•		•	•	•	●	
Flanges		•	•	•	•	•		•	•	•	●	
Bolts		•	•	•	•	•		•	•	•	●	
Piping		●	●	•	•	•		•	•	•	●	
Brackets		•	•	•	•	•		•	•	•	●	

INSPECTION METHODS – Groups 6–9

OTS COMPONENTS	6 SURVEY: Sonar (Bare-Surface, Overburden)	Surveying (Component Location, Mapping	Scour	7 OTS CONTROL: Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	8 SPECIAL METHODS: Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged Load Monitor	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	9 MFG - MISC: Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off	Magnetic Chip Detectors
Upstream From Pumps																						
Upstream-Piping							●	●									•					
-Flange							●	●		•							•					
Sampler-Drain Valve (Left Open)							●	●									•		●	●	●	
-Container																	•					
-Valve							●	●									•		●	●	●	
Strainer-Drain Valve (Left Open)							●	●									•		●	●	●	
-Basket								●									•					
Air Eliminator-Drain Valve (Left Open)							●	●									•		●	●	●	
-Chamber							●	●									•					
-High Level Switch																					●	
Bolts								•														
Flanges							●	●		•							•					
Pump Section																						
Piping							●	●									•					
Pump-Valve							●	●	●								•		●	●	●	●
-MOV							●	●	●								•		●	●	●	●
-Seals							●	●									•					
Bolts								•														
Flanges										•							•					
Downstream From Pumps																						
Meter Run-Valve							●	●									•		●	●	●	
-Control Valve							●	●									•		●	●	●	
-Straightener							●	●									•					
-Turbine Flow Meter							●	●											●	●	●	
-Flange							●	●		•							•					
Meter Prover-Valve							●	●									•		●	●	●	
-Diverter Valve							●	●									•		●	●	●	
-Drain																	•				●	
-Line							●	●									•					
Launcher-Valve							●	●									•					
-Container							●	●									•					
-Drain Valve (Left Open)							●	●									•				●	
-Gaskets							•										•					
Flanges							●	●		•							•					
Bolts								•														
Piping							●	●									•					
Brackets																						

NOTE:

1. Legend - • Potential Method; ● Method Selected for Cost-Effective Analysis in Section 4.4

2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

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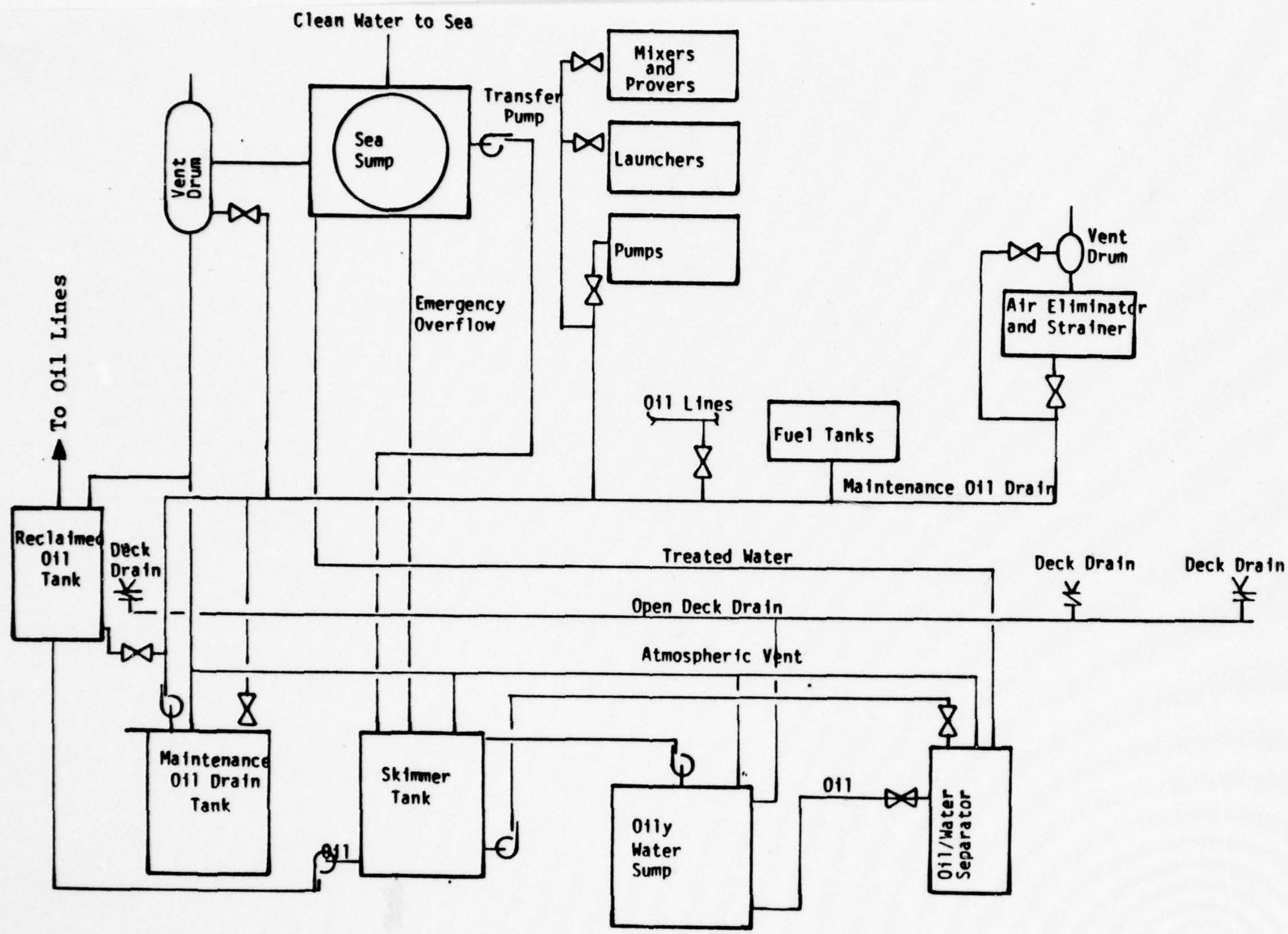

FIGURE 3-8 WASTE DISPOSAL SYSTEM

SOURCE: SEADOCK, INC.

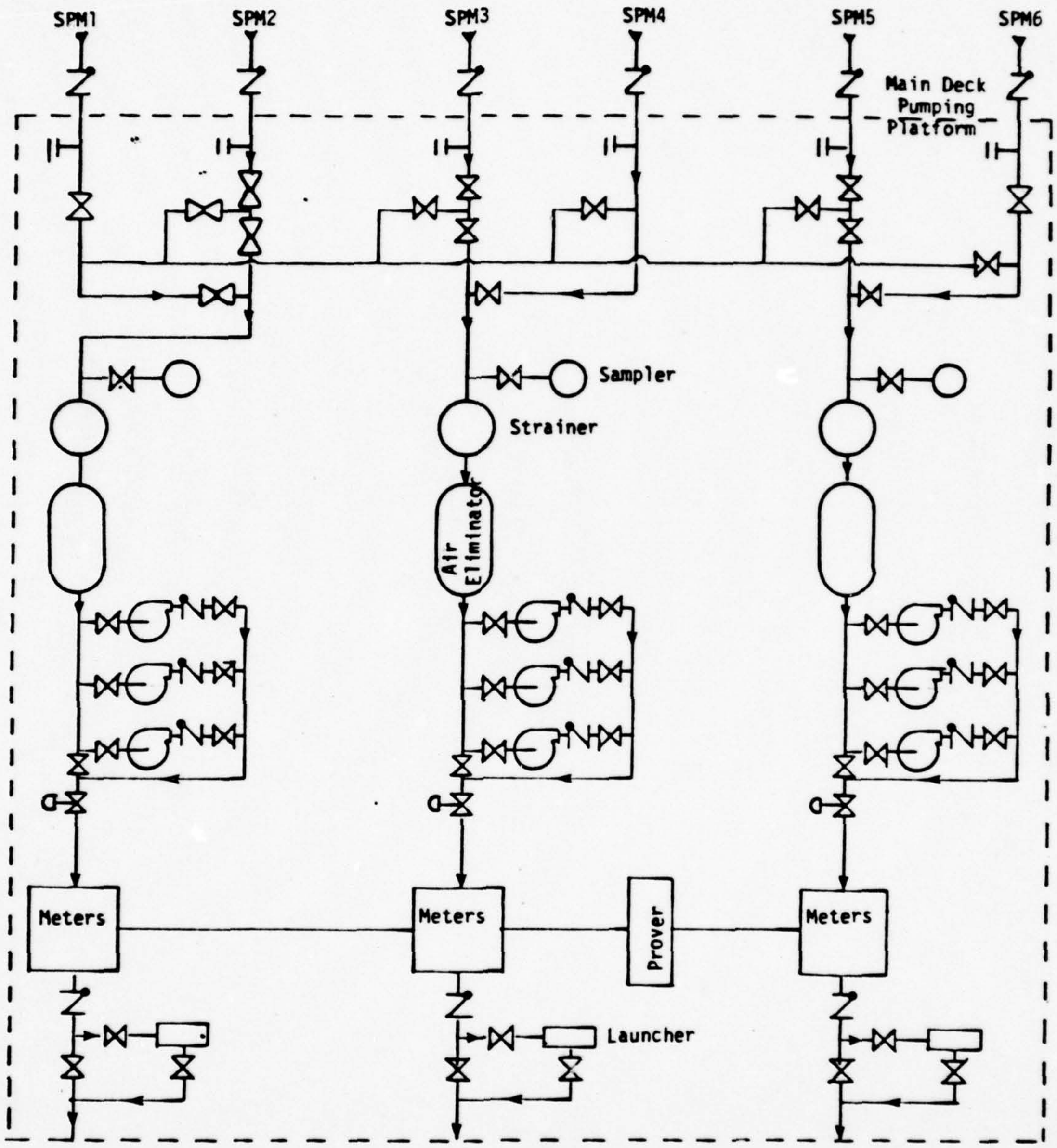

FIGURE 3-9 PUMPING PLATFORM SCHEMATIC

SOURCE: LOOP, INC.

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3.7 ONSHORE PIPELINE AND APPURTENANCES

The onshore pipeline inspection methods are given in Table 3-7 for both the underground and aboveground pipelines. These methods are essentially the same as those of the undersea pipelines except that underwater survey inspections are not required. Onshore booster station inspection methods also shown in Table 3-7 are essentially the same as for similar OTS components on the pumping platform.

3.8 ONSHORE STORAGE TERMINAL

Potential inspection methods for the onshore storage terminal are given in Table 3-8. The methods are given under the assumption that an oil spill prevention countermeasure and control (SPCC) program (Reference 41) is required for the onshore oil storage facility and a secondary containment system would be used both for the storage facility and the booster pump station. Newly designed and built facilities usually incorporate such containment systems.

TABLE 3-7 ONSHORE PIPELINE AND APPURTENANCES

OTS COMPONENTS / INSPECTION METHODS	1 VISUAL							2 OIL SPILL DETECTOR				
	Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type
ONSHORE PIPELINE AND APPURTENANCES												
Underground Pipeline				●								
Pipe				●	•							
Corrosion				●	•							
Defective Weld				●								
Rupture, Damage, Other Failures				●								
Cathodic Protection				●								
Seals				●								
Gaskets				●								
Flanges				●								
Valves				●								
Aboveground Pipeline				●								
Pipe				●	•							
Corrosion				●	•							
Defective Weld				●								
Rupture, Damage, Other				●								
Cathodic Protection				●								
Seals				●								
Gaskets				●								
Flanges				●								
Valves				●	•							
Booster Station												
Pump				●	●							
Block Valves				●	•							
Strainer				●	•							
Check Valves				●	•							

OTS COMPONENTS / INSPECTION METHODS	3 DYNAMIC INSERTIONS INTO OTS						4 CORROSION			
	Dye Tracing	Inspection Pig	*Hydrostatic* (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic	Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)
ONSHORE PIPELINE AND APPURTENANCES										
Underground Pipeline	●	●	●	●			●			
Pipe	●	●	●	●		•	●	●	•	●
Corrosion	•	●	●			•	●	●	•	●
Defective Weld	•	●	●			•				
Rupture, Damage, Other Failures	●	●	●	●		•	•			
Cathodic Protection								●		●
Seals	•	•	●							
Gaskets	•	•	●							
Flanges	•	•	●					●		●
Valves	•	•	●					●		●
Aboveground Pipeline	•	•	●	•		●	•			
Pipe	•	•	●	•		●	•	●	●	●
Corrosion	•	•	●			●	•	●	●	●
Defective Weld	•	•	●			●				
Rupture, Damage, Other	•	•	●			●	•			
Cathodic Protection								●		●
Seals	•	•	●							
Gaskets	•	•	●							
Flanges	•	•	●					●		●
Valves	•	•	●					●		●
Booster Station										
Pump	•		●							
Block Valves	•		●							
Strainer	•		●							
Check Valves	•		●							

OTS COMPONENTS / INSPECTION METHODS	5 NON-DESTRUCTIVE TESTING												6 SURVEY		
	Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements	Sonar (Bare-Surface, Overburden Pipeline)	Surveying (Component Location, Mapping)	Scour
ONSHORE PIPELINE AND APPURTENANCES															
Underground Pipeline													•	•	•
Pipe	●	●	•	●	●	•		●	•	•	•		•	•	•
Corrosion	●	●	•	●	●	•		●	•	•					
Defective Weld	●	●	•	●	●	•		●	●	•					
Rupture, Damage, Other Failures	•	●	•	●	●	•		●	•	•	●		•	•	
Cathodic Protection											●				
Seals	●	●	•	●				●			●				
Gaskets	●	●	•	●							●				
Flanges	●	●	•	●	●	•		●	•	•	●				
Valves	●	●	•	●	●	•		●	•	•	●				
Aboveground Pipeline															
Pipe	•	●	●	●	●	•		●	•	●	●				
Corrosion	•	●	●	●	●	•		●	•	●					
Defective Weld	•	●	●	●	●	•		●	●	●					
Rupture, Damage, Other	•	●	●	●	●	•		●	•	●	●				
Cathodic Protection															
Seals	•	●									●				
Gaskets	•	●	●	●				●			●				
Flanges	•	●	●	●	●	•		●	•	●	●				
Valves	●	●	●	●	●	•		●	•	●	●				
Booster Station															
Pump	●	●	●	●	●	•		●	•	●	●				
Block Valves	•	●	●	●	●	•		●	•	●	●				
Strainer	•	●	●	●	●	•		●	•	●	●				
Check Valves	•	●	●	●	●	•		●	•	●	●				

OTS COMPONENTS / INSPECTION METHODS	7 OTS CONTROL			8 SPECIAL METHODS												9 MFG - MISC			
	Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	Inspection Schedule and Maintenance	Operational Checks, Magnetic Chip Det.	Control Room Monitors, Alarms, Shut-off	Internal Pipeline Inspections-Visual, NOT
ONSHORE PIPELINE AND APPURTENANCES																			
Underground Pipeline	●	●	●	●	●			•		●	•								●
Pipe	●	●	●	●	●			•		●	•								●
Corrosion				●	•									●					●
Defective Weld				●	●									●					●
Rupture, Damage, Other Failures				●	●									●					●
Cathodic Protection																●			
Seals				●	•									●					●
Gaskets				●	•									●					●
Flanges				●	●									●					●
Valves				●	●									●		●	●	●	●
Aboveground Pipeline	•	•	•	●	●			•		•									
Pipe	•	•	•	●	●			•		•				●					•
Corrosion				●	•									●					•
Defective Weld				●	●									●					•
Rupture, Damage, Other				●	●									●					•
Cathodic Protection																●			
Seals				●	•									●					•
Gaskets				●	•									●					•
Flanges				●	●									●					•
Valves				●	●									●		●	●	●	•
Booster Station																		●	•
Pump				•	●	●										●	●	●	
Block Valves				●	●											●	●	●	
Strainer				●	●											●	●	●	
Check Valves				●	●											●	●	●	

NOTE:

1. Legend - • Potential Method; ● Method Selected for Cost-Effective Analysis in Section 4.4
2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

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TABLE 3-8 ONSHORE STORAGE TERMINAL

INSPECTION METHODS

OTS COMPONENTS	1 VISUAL: Visual-By Launch	Visual-On Deck of Ship	Visual-Diver, Submersible or Scuba	Visual-On Platform, Buoy or Land	Optical Borehole	TV Scanning With Onshore Monitoring	Tape Detection	2 OIL SPILL DETECTOR: Oil Spill Detector-On Launch	Oil Spill Detector-On Deck of Ship	Oil Spill Detector-On Platform	Oil Spill Detector-On Buoy	Oil Spill Detector-Buoy Type	3 DYNAMIC INSERTIONS INTO OTS: Dye Tracing	Inspection Pig	Hydrostatic (Pressure Drop)	Pressure Crack Wave	Vacuum (With Inspection Pig)	External Hydrostatic
ONSHORE STORAGE TERMINAL																		
Pipe and Manifold Above Ground				●									•		●	•		●
Corrosion				●									•		●			●
Defective Weld				●									•		●			●
Rupture, Damage, Other Failure				●									•		●			●
Cathodic Protection				●														
Seals				●									•		●			
Gaskets				●									•		●			
Flanges				●									•		●			
Valves				●									•		●			
Pipe and Manifold Underground (See TABLE 3-7)																		
Pig Receiving Trap (See TABLE 3-6)																		
Strainer (See TABLE 3-6)																		
Custodial Metering Rods (See TABLE 3-6)																		
Drainage Control System				●														
Retaining Dike				●		•												
Pipe Outlet				●									•					
Gate Valve				●									•					

OTS COMPONENTS	4 CORROSION: Flow Sampling (Coupons, Particles, etc.)	Corrosion-Meter (Volt., Cont.), Visual	Holiday Detector	Cathodic Protection (Mfg. Schedule)	5 NON-DESTRUCTIVE TESTING: Passive Ultrasonics	Active Ultrasonics	X-Ray	Radioactive Isotope, Gamma Ray	Magnetic Particle	Magnetic Rubber	Magnetic Foil or Magnetic Tape	Ultrasonic Imaging (3-Dimensional)	Eddy Current	Penetrants	Bolt Tightness (Torque)	Size Measurements
ONSHORE STORAGE TERMINAL																
Pipe and Manifold Above Ground	•		●	•	•	●	●	●	●	•		●	•	●	●	
Corrosion	•	●	●	•	•	●	●	●	●	•		●	●	●		
Defective Weld					•	●	●	●	●	•		●	•	●		
Rupture, Damage, Other Failure	•	●	•	•	•	●	●	●	●	•		●	•	●	●	
Cathodic Protection		•	•	•											●	
Seals					•	●	●	●				•			●	
Gaskets					•	●	●	●							●	
Flanges		●	•	•	•	●	●	●	●	•		●	•	●	●	
Valves		●	•	•	●	●	●	●	●	•		●	•	●	●	
Pipe and Manifold Underground (See TABLE 3-7)																
Pig Receiving Trap (See TABLE 3-6)																
Strainer (See TABLE 3-6)																
Custodial Metering Rods (See TABLE 3-6)																
Drainage Control System																
Retaining Dike																
Pipe Outlet		●	•	•	•	•	•	•	•	•		•	•	•	•	
Gate Valve		●	•	•	●	●	●	●	●	•		•	•	●	•	

OTS COMPONENTS	6 SURVEY: Sonar (Bare-Surface, Overburden)	Surveying (Component Location, Mapping)	Scour	7 OTS CONTROL: Pressure, Volume	Flow	Mathematical Modeling (Pressure, etc.)	8 SPECIAL METHODS: Passive Acoustic Array-Leaks	Passive Acoustic Array-Acoustic Emission	Passive Acoustic-Machinery Vibration	Strain-Gaged (Mooring Load Monitor)	Continuous Thermister	Laser Detection-Underwater	Shroud With EMP Pulsed Coaxial Cable	Double Walled Pipe	Double Walled Hose	External Load (i.e., Pulling by Ship)	Seal Leak Detector	Tank Liquid Level Sensor	9 MFG - MISC: Inspection Schedule and Maintenance	Operational Checks	Control Room Monitors, Alarms, Shut-off
ONSHORE STORAGE TERMINAL																					
Pipe and Manifold Above Ground				•	•	•	●	●			•		•	•			●				
Corrosion							●										●				
Defective Weld							●	●									●				
Rupture, Damage, Other Failure							●	●									●				
Cathodic Protection																					
Seals							●										●				
Gaskets							●										●				
Flanges							●	●									●				
Valves							●	●									●		●	●	●
Pipe and Manifold Underground (See TABLE 3-7)																					
Pig Receiving Trap (See TABLE 3-6)																					
Strainer (See TABLE 3-6)																					
Custodial Metering Rods (See TABLE 3-6)																					
Drainage Control System																					
Retaining Dike																		•			●
Pipe Outlet							•	•									•				
Gate Valve							•	•									•		●	●	●

NOTE:

1. Legend - • Potential Method; ●Method Selected for Cost-Effective Analysis in Section 4.4
2. Methods Shown for Major Components (i.e. Floating Hose String) Provide Inspection for the Component As a Whole

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4.0 COST EFFECTIVENESS OF INSPECTION METHODS

Inspection methods, which appear to have the best potential of those identified in Section 3 for a hypothetical deepwater port (a composite of SEADOCK and LOOP and described in Section 2.4 Reference and shown in Figure 4-1), were selected for further evaluation in this section. The primary evaluation consisted of weighing the cost of utilizing the inspection method versus the amount of reduced risk of oil spills, cost-effectiveness. The specific areas included in the cost-effectiveness analysis were:

1) Effectiveness, estimation of achievable risk reduction;
2) Cost of inspection and procedure;
3) Measure of cost-effectiveness of inspections;
4) Cost and effectiveness of component replacement;
5) Optimization of inspections and replacement intervals.

The effectiveness of inspection methods was measured, primarily, in terms of the reduced risk of *oil spills, barrels/year*. The evaluation proceeded by estimating the reduction of oil spill risk for each OTS component through application of each selected inspection method. This factor the was applied to the oil spill risk existing without inspection, from Table 3-14 in Reference 1, to calculate the annual barrels of oil not spilled. The factors considered in making these estimates are discussed in Section 4.1. The results of the estimates of effectiveness are presented in Section 4.4 for each of the major subsystems of the OTS.

The cost of each inspection method and procedure was estimated based on consideration of the factors discussed in Section 4.2. These factors included the cost of special equipment needed, manpower and downtime of the deepwater port. The cost estimates are presented in Section 4.4 along with the estimates of effectiveness.

The measure of cost-effectiveness was calculated as the ratio of barrels of oil not spilled per year to the inspection cost per year. These values also are tabulated in Section 4.4.

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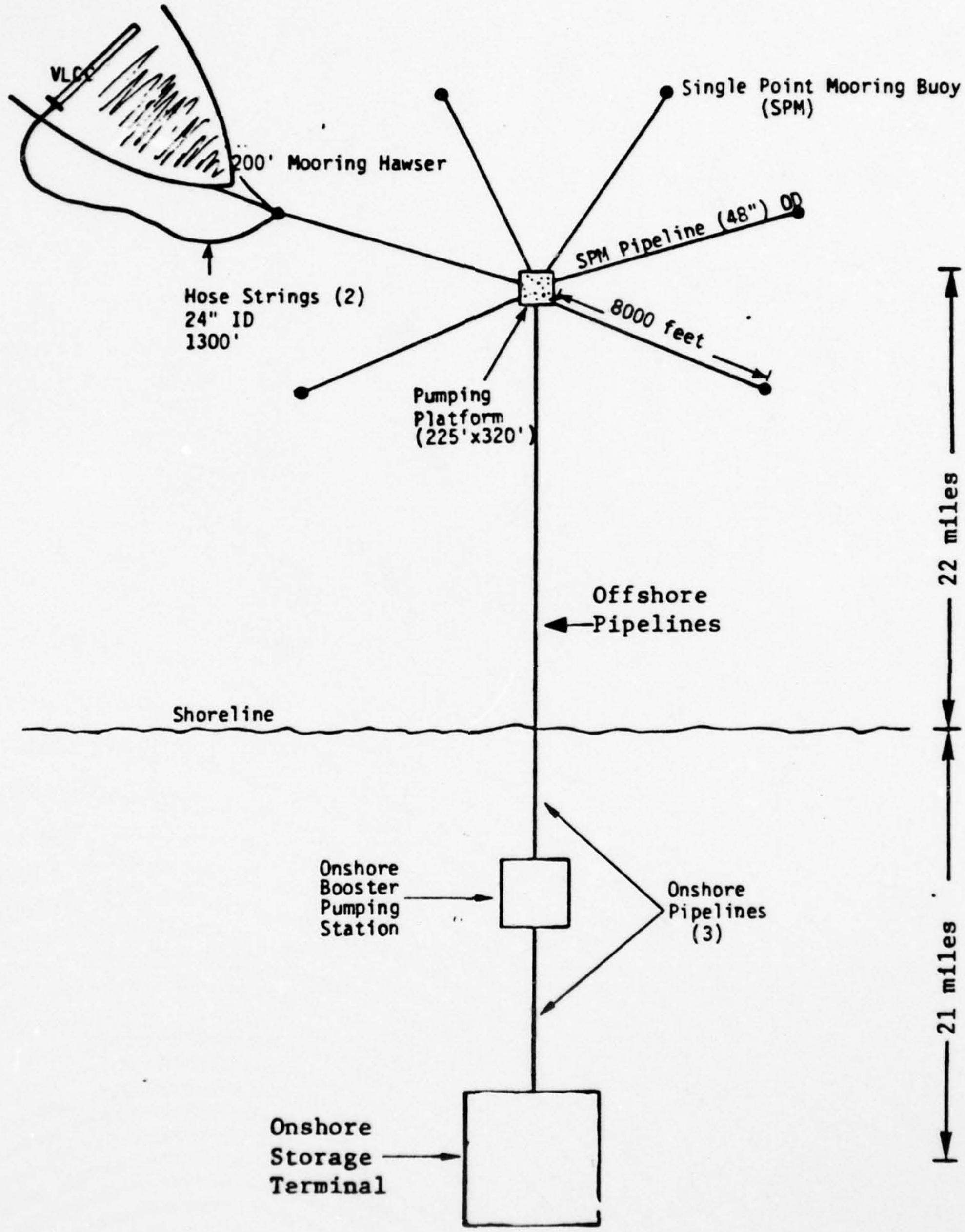

FIGURE 4-1 SKETCH OF OIL TRANSFER SYSTEM

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This measure was not the only factor used to recommend an inspection method or procedure. Another important consideration was the alternative replacement of the component. Its cost-effectiveness was estimated in a manner similar to that used for inspection methods, and the results also are presented in Section 4.4.

In addition, the frequency of inspections or replacements provides the flexibility for achieving the maximum ratio of reduced oil spilled to cost. This optimization also included consideration of backup and alternate inspection techniques and achieving a cost savings by applying the same inspection method to as much of the OTS as possible. The results of this optimization are included in the recommendations made in Section 5.0.

Finally, there still were other criteria used for recommending an inspection method in Section 5.0. These are discussed in Section 4.3. One of these is that a currently achieved, low-risk of oil spills from a subsystem of the OTS may be the result of currently used inspection methods. The continued use of these methods is recommended.

4.1 EFFECTIVENESS EVALUATION METHODOLOGY

4.1.1 Effectiveness Measured by Risk Reduction

The risk of oil spills is composed of two parts: the probability or frequency of a spill and the quantity of oil spilled. As mentioned in Section 2.3, some inspection techniques would be directed at reducing the frequency of spills whereas others would be directed at the early detection of spills in order to limit the amount spilled. Thus, one quantitative basis for judging the effectiveness of an inspection technique is the extent it can reduce frequency or limit the quantity of oil spilled.

However, there is another factor that must be considered. This is the level of oil spill risk that already exists or is inherent in the OTS. This was evaluated in the first phase of this study.

(Reference 1). A summary of the results of the study of the relative risk of oil spills from the OTS is given in Table 3-14 of Reference 1 and is repeated in this report, for convenience, in Table 4-1. It was found that in some cases the risk of oil spills is high, e.g., the floating hose strings or the buried underground or underwater pipeline. In others, the risk was low, e.g., spills from the pumping platform. Thus from a systems point-of-view, inspection of the hose strings potentially can effect a greater reduction of oil spill risk than can a comparable inspection for the piping and pumps on the platform.

The quantitative estimation of the reduction of oil spill risk achievable by an inspection technique was based in part on the failure mode affected and in part on engineering judgment. The extent to which a given failure mode contributes to oil spill risk was developed in the preceding safety analysis and is indicated in the fault trees and Tables 3-14 and 4-1 of Reference 1. Thus 100 percent effective inspections of the mooring systems, especially the mooring hawsers of an SPM, could substantially eliminate ship breakout. For six SPMs at a deepwater port, this could eliminate one of major risks of oil spills. Ship breakout is not a frequent occurrence during the operation of an SPM, but if this does occur the rupture of a hose and major oil spill could result. As another example, leaks from gaskets and seals of the oil piping of the SPM are expected to be 2 to 3 times more frequent than ship breakout, but the risk is less because of the smaller amounts expected to be spilled.

The ability of an inspection technique to limit the size or to eliminate the cause of a spill was based on engineering judgment. In making this judgment several factors were considered: frequency of the inspection, reliability and sensitivity. These factors are discussed in subsequent subsections.

4.1.2 Comparison of Exsiting and New Methods for Optimum Alternate or Backup Use

For detection of a specific failure in many components of the OTS subsystem, a number of new or alternative inspection methods are available in addition to the generally used existing methods.

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TABLE 4-1 RELATIVE RISK OF OIL SPILLS FROM THE OIL TRANSFER SYSTEM

SOURCE AND MODE	FREQUENCY (Per Yr)	SPILL SIZE*	NOMINAL SIZE (bbls)	RISK (bbls/yr)
SHIP	0.14	Minor, Medium	333	47
HOSE STRINGS NOT DURING OFFLOADING				
Leaks	0.24	Minor	15	3.5
Rupture	0.09	Minor, Medium	1,500	135
HOSE STRINGS DURING OFFLOADING				
Leaks	13	Minor	25	310
Rupture	0.6	Minor, Medium Major	4,800	2,880
SPM UNIT CALM				
Leaks	2.65	Minor	25	66
Rupture	0.15	Minor, Medium Major	5,000	750
SPM UNIT SALM				
Leak	1.2	Minor	25	30
SPM PIPELINE DURING OFFLOADING				
Leaks	9.0×10^{-4}	Minor, Medium	2,000	0.9
Rupture	3.8×10^{-4}	Minor, Medium Major	26,800	10
SPM PIPELINE NOT DURING OFFLOADING				
Leaks	2.5×10^{-3}	Minor	< 1 (Seep)	< 1
Rupture	1.6×10^{-3}	Minor, Medium Major	21,000	26
PUMPING PLATFORM				
OTS and Waste System Fails	7.9×10^{-5}	Minor	50	4×10^{-3}
Waste System Leaks	8.8×10^{-5}	Minor	50	4×10^{-3}
Damage to Platform	3×10^{-4}	Minor, Medium, Major	4,000	1.2
PLATFORM TO SHORE PIPELINE				
Leaks (During Pumping)	0.034	Minor, Medium	1,000	34
Rupture	0.001	Minor, Medium Major	100,000	1,000
ONSHORE PIPELINE				
Leaks (During Pumping)	0.032	Minor, Medium	1,000	32
Rupture	0.01	Minor, Medium Major	100,000	1,000
SPILL FROM ONSHORE FACILITY				
Leaks	3×10^{-5}	Minor, Medium	1,000	0.03

NOTE:* Minor Spill, < 10,000 gal (238 barrels); Medium Spill, 10,000 to 100,000 gal; Major Spill, >100,000 gal (2380 barrels).

4-5 (87)
95%

All of these suitable methods were evaluated based on sensitivity, cost, reliability, etc., and the optimum one selected. However, a selected method may not be optimum in certain circumstances, such as bad weather conditions, and an alternate method was recommended. For example, ultrasonic—imaging inspection by a diver of the PLEM piping may be the best method, but excessive wave motion may restrict its use so that an alternate method such as active utrasonics would be required. If a diver cannot be used, examination of data from a back-up continuous inspection method such as passive acoustics might be required.

4.1.3 Evaluation of Sequential and Simultaneous Inspection Methods

Sequential use of different inspection methods will be considered because it can provide increasing levels of inspection detail which may be advantageous for inspecting some OTS components. Generally, a three-step approach would be followed:

(1) Determine if a defect exists with a simple low-cost inspection method this could be done, for example, by using visual or liquid penetrant inspection for finding cracks in above ground piping or manifolds.

(2) Rough sizing of defect with a more sensitive inspection method this could be done, for example, by using higher cost ultrasonic inspection if a crack is detected.

(3) Quantitative sizing to determine if component replacement or repair is required- this could be done, for example, by using very high-cost X-ray or ultrasonic imaging inspection methods.

Simultaneous use of different inspections is necessary when more than one critical defect can occur in an OTS component and these cannot be inspected adequately by the same method.

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4.1.4 Variation of Frequency of Inspection to Reduce Risk of Oil Spills

An important consideration for periodic inspections is the length of time between each inspection. Practice makes this a trade-off between the cost and resources required for the inspection and the anticipated likelihood of component failure. Application of this practice will not eliminate failures of equipment and spills but will insure a low low frequency of spills consistent with the costs and consequences of an oil spill. According to theory (References 39 and 40), the likelihood of a leak depends on the probability that one or more components of a system is in a failed state (e.g., a collapsed hose liner or a hole in the pumping platform deck). This latter probability, in its simplest form, is the product of the failure rate and the length of time the failure can remain undetected. If the system is inspected at regular intervals, the detection time, on the average, is one-half the interval between inspections (References 42 and 43). Thus failure probability decreases in direct proportion to frequency of inspection.

The application of this theory requires knowledge of failure rates. As indicated in Appendix C of Reference 1, failure rate data are available for many common items of equipment such as pumps, valves, gaskets, flanges, etc. Most of these items comprise the more conventional parts of the OTS, those of the onshore pipeline system and those of the pumping platform. However, failure rate data for many of the items comprising the SPM and the floating hoses do not exist. Instead only some spill frequencies have been derived from incomplete data. These data together with the fault trees and the failure-mode-and-effects analysis in Reference 1 were used to develop estimates of failure rates for parts of the hose string and SPM. The details of the estimations are described in the appropriate sub-sections of Section 4.0.

4.1.5 Variation of Inspection Methods That Limits Quantity of Oil Spilled

Variation of inspection methods that limit the quantity of oil spilled has to do with the ability of a technique to detect a

onset of a leak. For example, the flow meters and data processing equipment would have the capability to detect leaks in the platform-to-terminal pipeline of approximately 1 percent of the flow. Smaller leaks would not be detected. As a complementary system, a passive acoustic array installed along the pipeline, could detect small leaks but would not be especially effective for large leaks. Another example is the visual inspection of a floating hose string from a launch. This procedure would have the capability to detect kinking of a hose and serious damage to the floats and hose carcass but not incipient failure of a hose-nipple bond. Judgment as to the sensitivity of the many inspection methods included consideration of manufacturer's data and experience in the field.

4.1.6 System Effectiveness

System effectiveness takes into account inspection system reliability, operational readiness and design adequacy and will be an important consideration in the selection of the optimum inspection method. It can be used to quantify the overall effectiveness of inspection methods. The concept will be discussed briefly here. A more detailed discussion that includes a specific example is given in Reference 44. System effectiveness provides a quantitative measure of the extent to which an inspection system may be expected to accomplish an inspection successfully under specified conditions. The system effectiveness (P_{SE}) is defined as

$$P_{SE} = P_R \times P_{OR} \times P_{DA},$$

Where P_R = reliability, the probability that the inspections system will operate satisfactorily during the total inspection time. It relates to the frequency to which system failure occurs while in use. In the simplest case it can be assumed that uncontrolled failures (such as component failure) occur at random and its reliability can be defined as

(90)

$$P_R = e^{-t/0},$$

where

t = total inspection time,

0 = mean time between failures.

P_{OR} = Operational Readiness, the probability that the system is operating or ready to be placed in operation. Here the main concern is the probability that the inspection system will be operating at any random point in time rather than over an interval of time. It can be defined as

$$P_{OR} = P_A(1-P_S) + R_1P_S,$$

where

$$P_A = \text{Availability} = \frac{\text{(Total Operating Time)}}{\text{(Total Operating Time)}+R_2\text{(Total Down Time)}}$$

$$R_2 = \frac{\text{Demand (Usage Time)}}{\text{Total Calendar Time}}$$

$$R_1 = \text{Assume} = 1$$

$$P_S = \frac{\text{Non-Inspection Up Time}}{\text{Total Calendar Time}} .$$

P_{DA} = Design Adequacy, the probability that the inspection system will successfully accomplish its performance requirements. In simple inspections P_{DA} may be unity. If it is used for a difficult inspection that may be hard to carry out such as by a diver inspecting a component that is moving slightly, the P_{DA} value may be much lower.

For OTS component inspection where system effectiveness may be low, i.e., 0.5, the overall system effectiveness can be raised significantly by employing approaches such as using two inspection methods for the same inspectable component or providing spare inspection systems.

4.1.7 Evaluation of Inspection Methods with Multiple Uses to Reduce Cost

Some inspection methods can be used for a variety of inspections. This becomes an important consideration particularly when an inspection method may be too costly is used for only one specific

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inspection but may be of acceptable cost if it can be used for other inspections which help to defray its cost.

4.2 INSPECTION COSTS

All significant inspection costs must be obtained in order to properly evaluate the cost-effectiveness of a particular inspection method. This is necessary because for many OTS subsystem components more than one suitable inspection method is available and cost consideration in most instances would be the most important factor in the recommended inspection method and procedure. This is important, for example, when the frequency of a periodic inspection method is evaluated with either continuous monitoring or component replacement intervals. Inspection costs which were used are discussed in the following subsections.

4.2.1 Equipment

The equipment required for a particular inspection method and procedure consists of the basic inspection equipment but could also include items such as:

- Support equipment,
  - Rowboat
  - Power launch
  - Power supplies
  - Pumps
  - Diving equipment
  - Monitoring equipment
  - Equipment for permanent records
  - Other;
- Spare parts;
- Backup equipment,
  - Replacement inspection equipment
  - Alternate inspection equipment.

Equipment required to perform inspections might range from little more than a rowboat to a powered launch with diving gear, ultrasonic inspection devices, cleaning hoses and underwater TV with videotape recording. All well-maintained facilities require a reasonable amount of spares, tools, and backup equipment based initially on manufacturer's recommendations (which may or may not be followed religiously) and later on experience gained at the particular installation. Backup inspection equipment is required in the event of loss, damage, routine maintenance or failure of the primary equipment. Different operators may elect to keep on hand anything from a bare minimum of spares to an inventory sufficient to meet almost any eventuality. The former method might often prove to be more expensive in the long run when one considers the downtime experienced while waiting for spares to be delivered and the cost of shipment, in most cases by air.

In the case of offshore platforms, sufficient redundancy is provided to almost eliminate the need to shut down for any significant period. While the application of redundancy to SPM's is obviously much less feasible than on a platform, the possibility of utilizing it to a limited degree may exist. In an extreme case, a completely redundant SPM, used only in the event of major failure of the primary SPM, might prove to be cost effective.

The significant costs of all the necessary equipment will be considered. Costing will include items such as:

- Capital expense;
- Rental;
- Maintenance;
- Repair;
- Storage;
- Overhaul;
- Taxes.

4.2.2 Manpower

Manpower costs for conduction of various inspection methods and procedures can vary widely depending upon the type of inspection, inspection duration, inspection equipment and level of skill required. These costs are estimated in this study on a manhour basis because of the large variations in manhour costs that result from variable items such as DWP geographic locations, labor rates, local regulations, etc. These manpower manhour estimates for each inspection method and procedure will include all necessary personnel such as:

- Terminal operators (port superintendent, cargo transfer supervisor, vessel traffic supervisor, cargo transfer assistant, mooring master, etc.);
- Support personnel (divers, launch operators, inspectors, technicians, etc.);
- Backup personnel (divers, launch operators, inspectors, technicians, etc.);
- U.S. Coast Guard personnel.

Manpower costs for inspection may vary widely depending upon the inspection and the thoroughness and frequency with which inspections are performed. The services of one or more divers are a particularly important cost factor. Continuous visual-type inspections conducted at a facility by launch will increase the manpower costs by many orders of magnitude as compared with facilities which conduct only limited periodic visual inspections.

Manpower costs for future U.S. installations may or may not exceed those incurred by the better maintained facilities of today. On the one hand, labor rates and training costs will be higher and specialists will be needed to operate, maintain and evaluate the data from more sophisticated inspection equipment. On the other hand, the introduction of this equipment — some of it operating automatically and continuously —

may prove, in the long run, to require fewer manhours than are required to provide continuous inspections by launch as well as lessen the need for divers.

4.2.3 Facility Downtime

Various inspection methods and procedures, repairs and replacement of OTS subsystem components may require both DWP facility and Coast Guard downtime. These costs will be included in inspection costs. Downtime costs can be very expensive because when a facility is not operating, it is not only not making money, it is losing money primarily through demurrage and the cost of idle manpower. However, at efficiently run DWP facilities, these downtimes can be generally scheduled in between tanker offloading, and costs can be substantially reduced.

Although effective inspection methods and procedures, repair and replacement may require downtime, they may, in the long run, actually reduce downtime costs by reducing oil spill incidents. These incidents obviously cannot be scheduled so downtime costs could be assumed to be quite high.

A marginal operator may accept what he considers to be minor leakage as a profitable alternative to incurring downtime or he may decide to make a temporary repair which may only delay, rather than prevent, a major spill. A more conscientious operator might shut down while a permanent repair is made. Each may feel that he has taken the most cost-effective course but the former is gambling while the latter is taking a conservative action which is nonetheless costly and which might well have been avoided if more effective inspection procedures had been followed. In any case, it seems evident that the cost of frequent and thorough inspections would be more than offset by reduced downtime.

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4.2.4 Other Costs

The major costs of making inspections have been addressed. However, there are a number of other costs that may be required for certain inspection methods, repairs or replacements. They may include items such as:

- Personnel training;
- Support personnel;
- Inspection lead times;
- Environmental constraints;
- Other.

4.3 OTHER CONSIDERATIONS FOR THE EVALUATION OF INSPECTION METHODS

4.3.1 Inspection Lead Time

Ideally, it should be possible to conduct inspections while transfer operations are taking place or when the facility is idle. The inspection process itself should not be the cause of any more facility downtime than is absolutely necessary to prevent or terminate spillage. The preparations which must be made before an inspection is begun, while important for reasons of safety and dependable results, should also be capable of implementation without incurring facility downtime. Unduly long lead times could also result in a decreased frequency of inspections and could, therefore, be self-defeating in terms of achieving an efficient inspection program.

4.3.2 Special Training

Although above-water visual inspection techniques require little or no special training, use of other more advanced techniques proposed in this study will require a somewhat higher level of training to operate equipment and evaluate results. This factor should be held to a minimum, consistent with the need to achieve an effective inspection program. Inspection methods and equipment should be selected with a view toward their ability to provide easily interpreted and unambiguous results which can readily be applied by non-specialized and relatively unskilled personnel.

Whatever training is determined to be required should, at least in part, be given by qualified instructors in a classroom environment rather than the on-the-job training which is common today. Again it should be emphasized that the motivation of inspection personnel is an important factor and should be an integral part of any training program.

4.3.3 Environmental Constraints

Two types of environmental constraints must be considered in the evaluation of inspection methods. The first concerns the operating

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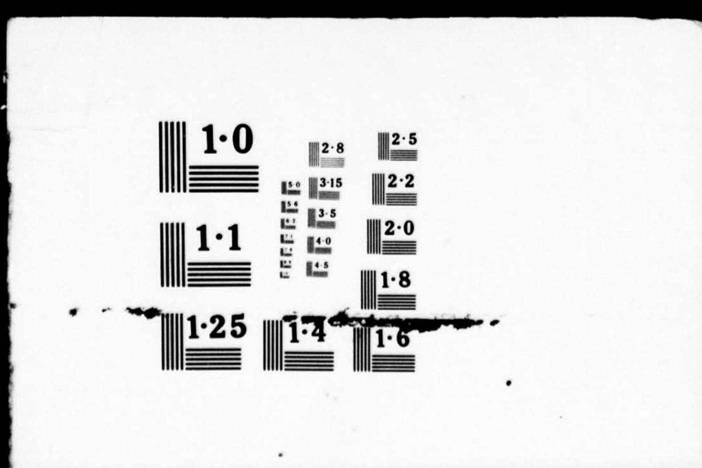

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and physical environment existing at a particular DWP. The incidence and severity of inclement weather, as well as the percentage of time the SPM is unoccupied by a tanker, can have a bearing on whether one inspection technique might be preferable to another. TV monitors and laser detectors, for example, are weather-limited, while many inspections performed by divers must be made when there is no ship in the berth or in calm sea. In addition, facilities which are subject to frequent storms will require more frequent post-storm inspections than the average facility.

The second type of environmental constraint concerns the amount and kind of pressure exerted by local governmental and environmental groups. In U.S. waters, this pressure will be uniformly strict and will preclude the use of practices such as deliberately using a component until failure occurs.

4.3.4 Inspection Versus Replacement

Replacement of vulnerable components on a regular, conservative schedule, based on manufacturers' recommendations or on experience gained at a given facility, can be an effective means of minimizing spillage. Since hoses have proven to be the most vulnerable link in the chain, a conscientious replacement policy with respect to hoses should significantly reduce the frequency and volume of spills. Downtime, at all but the busiest facilities, would be minimized by replacing the hoses (or other components) between ship visits.

The expense of replacing components which may still have a considerable amount of useful life remaining must be weighed against the potentially much greater expense which could result from a catastrophic failure. Additionally, the ability to perform extensive onshore testing of replaced components will, in many cases, reveal that their condition is such that they may be economically rebuilt or used "as is" for emergency spares.

While even a rigorous replacement program will not eliminate the need for inspections, it merits serious consideration as an important element in an effective spillage-prevention plan.

4.4 COST-EFFECTIVENESS ANALYSIS OF SELECTED INSPECTION METHODS FOR OTS SUBSYSTEM

This section provides a discussion and a quantitative cost-effectiveness analysis (using the approach described in Section 4.0) of the inspection methods and procedures that have been selected for further evaluation for inspecting the OTS. The hypothetical deepwater port OTS, which is a composite of SEADOCK and LOOP, is divided into nine main subsystems. Each is discussed and analyzed separately in nine major sections. Each major section is divided into two subsections described in the following two paragraphs.

In the first subsection, the OTS subsystem components are briefly described and relative oil risks reviewed. Then the selected inspection methods and procedures are first identified in a table along with inspection intervals, costs, risk reduction factors and effectiveness. These inspection methods and procedures are discussed briefly, including specific type, application, mode, degree, duration, sensitivity and usage.

The second subsection covers the effectiveness of the inspection methods and procedures. First, a detailed discussion is given describing how risk reduction factors for OTS component failures were determined for selected inspection methods and procedures. Then, how the effectiveness (reduced barrels of oil spilled and also system effectiveness) was determined is discussed and specific examples with sample calculations are presented. To simplify comparisons of inspection methods, the effectiveness values were based on the ability of the specific inspection methods indicated in the tables to reduce the risk of oil spills to below the risk estimated in Reference 1. The latter values reflect the efficacy of inspections for the OTS utilized during 1970-1971. The effectiveness values also were based upon implementations of inspection methods that are either commercially available or in the developmental or engineering design phase. This is important when a

variety of implementations of a specific inspection method are available or when potential inspection methods are in the feasibility stage or are untested. For example, many types of oil spill detectors are in the feasibility or developmental stage, but it is doubtful that more than a few will be funded for development and testing. This is because the oil spill detection field has been in existence for over seven years and most of the more promising detectors are either available commercially or in the engineering phase.

4.4.1 Hose String

4.4.1.1 Selected Inspection Methods for Hose Strings

According to Section 3 of Reference 1, the risk of oil spills from the hose string during offloading are the highest of all the major DWP OTS components. Oil spill risks also exist during the time when offloadings are not in progress, but the risks are of a much lower value. Spill risks are shown in Table 4-1. Basic hose string configurations and components for SALM or CALM SPMs are shown in Section 3-2. Six SPMs are expected to be used at the DWP. Each SPM would be equipped with two hose strings for offloadings. The basic hose string is 1000 to 1300 feet in length and comprised of 30 to 40-foot sections of 24-inch diameter flexible floating hoses and submarine hoses with flanged ends bolted together. The hose strings will, in most instances, be left floating and filled with oil during the time when offloadings are not being carried out. Several inspection methods for hose strings were selected for the following reasons:

(1) High oil spill risks;
(2) Hose string dimensions and configuration;
(3) Information presented in previous sections;
(4) Availability of a number of suitable inspection methods that have a potential for significant reductions in oil spill risk.

The selected inspection methods together with inspection frequency, estimated cost, risk reduction factors and effectiveness are listed in Table 4-2. Application of methods to specific components was identified in Table 3-2.

SALM and CALM Floating Hose Strings During Offloading

Continuous monitoring, both day and night and in all types of weather, is the most effective approach to inspection for reducing the risk of oil spills. Four inspection methods are given in Talbe 4-2 that can satisfy these objectives.

The most promising continuously monitoring method is an acoustic array system (Appendix B and Table 3-1). According to its developer*, the inspection method can immediately detect and locate the acoustical sounds emitted from hoses that are leaking at rates as low as a barrel an hour. The acoustic system is capable of instantaneous hose rupture detection and hose incipient failure detection. This is accomplished by recording and processing the known characteristic acoustical sounds (acoustic emissions occur in a known profile) that are generated at areas that are undergoing failure inside the hose but before a leak or rupture occurs. Acoustic detectors would be installed on hoses most likely to fail (first two hoses of the buoy, hoses that break the water, etc.). Data would be continuously monitored and an alarm sounded prior to failure or during actual leakage. System electronics would be installed on the buoy and the data telemetered to ship or platform in a manner similar to the commercially available mooring load monitor systems (see Appendices A and B).

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* Acoustic array inspection method is in the DWP testing and engineering phase. A number of successful tests have been carried out on SPM-type hoses over the past four years for leak detection, incipient failure and rupture detection.

TABLE 4-2 COST-EFFECTIVENESS ANALYSIS FOR HOSE STRING

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements		Risk Reduction Factor (2),(3),(4)		Effectiveness (6) Oil (5)		Comments
		Freq./Year	($K) (1)	Comp. Failure	System Failure	Saved Barrels Oil	Cost Barrels/($K)	
HOSE STRING DURING OFFLOADING								
(A) Floating Hose String CALM Floating Hoses and Tail Hoses - Includes Nipples, Flanges, Seals and Bolts	1(a) Visual by launch	once/ship	NA	NA	NA	NI	NA	
	(b) Visual by launch	once/2hrs	350	0.7	0.9	180	0.5	No instantaneous rupture detection
	(c) Visual by launch	cont.	700	0.5	0.8	800	1.1	
	2(a) Oil spill detector with launch	once/2hrs	358	0.5	0.9	300	0.8	No instantaneous rupture detection
	(b) Oil spill detector with launch	cont.	708	0.3	0.7	1100	1.6	
	3 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	4 Visual on buoy	cont.	367	0.6	0.8	640	1.7	Instantaneous rupture detection
	5 TV monitor on buoy (LL)	cont.	155	0.5	0.8	500	3.2	
	6(a) Tape detection monitored by launch	once/8hrs	640	0.1	0.8	540	0.8	Leaks and incipient rupture only
	(b) Tape detection monitored by launch	cont.	1132	0.1	0.5	1440	1.3	Detects rupture and incipient rupture
	7 (a) Buoy type oil spill det.	cont.	188	0.9	NEG	60	0.3	4 per SPM
	(b) Oil spill det. on ship	cont.	77	0.9	NEG	60	0.8	
	8 OTS control system (pressure flow)- 1% accuracy	cont.	150	0.1	0.7	900	6	Instantaneous rupture detection only Monitors on ship, SPM
	9 OTS control system Mathematical modeling 0.1% accuracy	cont.	170	0.05	0.7	950	5.6	Instantaneous rupture detection only Monitors on ship, SPM
	10 Acoustic array	cont.	182	0.1	0.5	1440	8	
	11 Shroud with EMP pulsed coaxial cable	cont.	166	0.3	0.9	420	2.5	Leaks and incipient rupture only
	12(a) Double walled hose	cont.	2,500	0.1	0.6	1440	0.6	
	(b) Double walled hose	once/2hrs	2,200	0.15	0.8	510	0.2	Leaks and incipient rupture only
	(c) Double-walled hose	once/8hrs	2,000	0.2	0.9	480	0.2	Assume 2-year life
	13 Inspection during hookup and operational checks	once/ship	NA	NA	NA	NI	NA	
	14 TV monitor(LL)on ship	cont.	32	0.7	0.9	480	15	Aids visual inspection
	15 Fluorescent	cont/night	28	0.7	0.9	480	17	Aids visual inspection
Butterfly Valve	1 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	2 Operational checks	once/ship	NA	NA	NA	NI	NA	
Other Components Anticollision blinker light	1(a) Visual by launch	once/ship	NA	NA	NA	NI	NA	
	(b) Visual by launch	cont.	700	0.9	NEG	40	<0.1	
Flange and bolts	2 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
Flange seals Floatation collar Floats Brackets and bolts Spreader bars and bolts Pickup buoy and support rope Chain	3 TV monitor on buoy	cont.	-	NEG	NEG	IND	0	

NOTE: (1) Inspection or replacement cost estimates based on yearly costs amortized over a ten-year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14. Risk reduction factor is estimated for the component (if appropriate, also for indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section 3.
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.

TABLE 4-2 (Continued)

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements Freq./Year	($K)(1)	Risk Reduction Factor (2),(3),(4). Comp. Failure	System Failure	Effectiveness (6) Oil Saved(5) Barrels Oil	Cost Barrels/($K)	Comments
(B) FLOATING HOSE STRING-SALM								
Floating Hoses and Tail Hoses - Includes Nipples, Flanges, Seals and Bolts	1(a) Visual by launch	once/ship	NA	NA	NA	NA	NA	
	(b) Visual by launch	once/2hrs	350	0.7	NEG	150	0.4	No instantaneous rupture detection
	(c) Visual by launch	cont.	700	0.5	0.8	670	1	
	2(a) Oil spill detector with launch	once/2hrs	358	0.5	0.9	250	0.7	No instantaneous rupture detection
	(b) Oil spill detector with launch	cont.	708	0.3	0.7	930	1.3	
	3 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	4 Visual on buoy	cont.	367	0.7	0.9	250	0.7	Extremely dangerous. Not recommended for current SALM buoy designs.
	5. TV monitor on buoy (LL)	cont.	155	0.7	0.9	390	2.5	Impractical for current buoy design
	6(a) Tape detection monitored by launch	once/8hrs	640	0.1	0.9	450	0.7	Leaks and incipient rupture but no early rupture detection
	(b) Tape detection monitored by launch	cont.	1132	0.1	0.6	1200	1.1	Detects rupture and incipient rupture
	7 (a) Buoy type oil spill det.	cont.	188	0.9	NEG	50	0.3	4 per SPM
	(b) Oil spill det. on ship	cont.	77	0.9	NEG	50	0.7	
	8 OTS control system (pressure flow)- 1% accuracy	cont.	170	0.1	0.8	750	4.4	Monitors on ship, PLEM and pumping platform Instantaneous rupture only
	9 OTS control system-mathematical modeling (pressure, flow, temp., etc.)- 0.1% accuracy		190	0.05	0.8	790	4.1	Instantaneous rupture only Monitors on ship, PLEM and pumping platform
	10 Acoustic array	cont.	186	0.1	0.6	1200	6.5	Detectors installed on hoses most likely to fail Detects leaks, rupture incipient failure, breakout
	11 Shroud with EMP pulsed coaxial cable	cont.	166	0.3	0.9	350	2.1	Detects leaks and incipient rupture
	12(a) Double walled hose	cont.	2,500	0.1	0.6	1200	0.5	Early detection and incipient failure
	(b) Double walled hose	once/2hrs	2,200	0.15	0.9	430	0.2	
	(c) Double walled hose NOTE: requires launch for inspection of hoses	once/8hrs	2,000	0.2	0.9	400	0.2	Assume 2 year life
	13 Inspection during hookup and operational checks	once/ship	NA	NA	NA	NI	NA	
	14 TV monitor(LL)on ship	cont.	32	0.7	0.9	390	12	Aids visual inspection
	15 Fluorescent light	cont/night	28	0.7	0.9	390	14	Aids visual inspection
Butterfly Valve	1 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	2 Operational checks	once/ship	NA	NA	NI	NA	NA	
Other Components Anticollision blinker lighting Flanges and bolts Flange seals Floatation collar Floats Brackets and bolts Gaskets and bolts Spreader bars and bolts Pickup buoy and support rope Chain	1(a) Visual by launch	once/ship	NA	NA	NA	NI	NA	
	(b) Visual by launch	cont.	700	0.9	NEG	40	<0.1	
	2 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	3 TV monitor on buoy	cont.	-	NEG	NEG	IND	0	

95%

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TABLE 4-2 (Continued)

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements Freq. Year	$K) (1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	System Failure	Effectiveness(6) Oil(5) Saved Barrels Oil	Cost Barrels ($K)	Comments
(C) SUBMARINE HOSE STRING - SALM ONLY								
Underwater Hoses - Includes Nipples, Flanges, Seals and Bolts	1(a) Visual by launch	once/ship	NA	NA	NA	NI	NA	
	(b) Visual by launch	once/2hrs	350	NEG	NEG	IND	0	
	(c) Visual by launch	cont.	700	0.9	NEG	20	< 0.1	
	2(a) Oil spill detector with launch	cont	708	0.8	NEG	30	< 0.1	
	(b) Oil spill detector with launch	once/2hrs	352	0.9	NEG	IND	0	
	3 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	4.(a) Buoy-type oil spill detec.	cont.	185	0.9	NEG	20	0.1	4 per SPM
	(b) Oil spill detec. on ship	cont.	77	0.9	NEG	20	0.3	
	5 OTS control system (pressure flow) - 1% accuracy	cont.	150	0.1	NEG	150	1	Instantaneous rupture detection only
	6 OTS control system Mathematical modeling (pressure, flow, temp, etc.) - 0.1% accuracy	cont.	170	0.05	0.9	160	0.9	
	7 Acoustic array	cont.	135	0.1	0.9	240	1.8	
	8 Shroud with EMP pulsed coaxial cable	cont.	123	0.3	0.9	190	1.5	
All Other Components (See Table 3-2)	No methods							Inspect only when not offloading
HOSE STRING NOT DURING OFFLOADING								
(D) FLOATING HOSE STRING - CALM								
Floating Hoses and Tail Hoses - Includes Nipples, Flanges, Seals and Bolts	1(a) Visual from launch	52	NA	NA	NA	NI	NA	
	(b) Visual from launch	365	136	0.9	NEG	60	0.4	
	2(a) Oil spill detectors with launch	52	29	0.9	NEG	60	2	
	(b) Oil spill detector with launch	365	145	0.5	0.9	300	2	
	3 Visual by diver	leak detected on surface	NA	NA	NA	NI	NA	
	4 Visual by diver	after storm	NA	NA	NA	NI	NA	
	5 Optical borehole	6	37	0.5	0.9	300	8.1	Evacuate hose string
	6 TV monitor on buoy (LL)	cont.	155	0.9	NEG	60	0.4	
	7 Tape detection monitored from launch	365	609	0.7	0.9	180	0.3	
	8 Dye tracing (water in hoses)	26	106	0.1	0.8	540	5	Incipient leak detection
	9 Vacuum with TV inspection pig	2	100	0.8	NEG	120	1.2	
	10 Hydrostatic		60	0.5	0.9	300	5	Use with leak detection method
	11 Acoustic array	cont.	173	0.1	0.8	540	3.1	
	12 Double walled hose	365	2100	0.1	0.8	540	0.3	
	13 Shroud with EMP pulsed coaxial cable	cont.	192	0.3	0.9	420	2.2	
	14 Diver NDT and Visual (see recommended schedule Section 5.2)			0.5	0.9	300		
	15 Water left in hose string		45	0.01	NEG	120	2.7	
	16(a) Hose string replacement schedule and/or onshore inspection	2	10700	0.5		300	0.03	
		1	5340	0.9		60	0.01	
		1/2	NA	NA	NA	NI	NA	May increase risk
	(b) Tail hose	2	NA	NA	NA	NI	NA	
		3	918	0.9	Neg.	30	0.03	
		4	1224	0.5	0.9	150	0.01	
	(c) First hose off CALM	1	NA	NA	NA	NI	NA	May increase risk
		2	612	0.9	NEG	30	0.05	
	17 5 and 14			0.3	0.3	420		

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TABLE 4-2 (Continued)

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements Freq. Year	($K)(1)	Risk Reduction Factor(2),(3),(4) Comp. Failure	System Failure	Effectiveness(6) Oil (5) Saved Barrels Oil	Cost Barrels ($K)	Comments
Butterfly Valve	1 Visual by diver	after storm	NA	NA	NA	NI	NA	
	2 NDT - (see recommended schedule Section 5.2)		-	NEG	NEG	IND	0	
Blind Flange	1 Replacement	1/5	NA	NA	NA	NI	NA	
	2 NDT and Visual - (see recommended schedule Section 5.2 and Table 3-2)		-	NEG	NEG	IND	0	
Other Components: Anticollision blinker light; Flanges and bolts; Floatation collar; Floats; Brackets and bolts; Spreader bars and bolts; Pickup buoy and support rope; Chain	1(a) Visual from launch	once/ship	NA	NA	NA	NI	NA	
	(b) Visual from launch	365	-	NEG	NEG	NI	NA	
	2 Visual by diver	after storm	NA	NA	NA	NI	NA	
	3 Diver NDT and visual (see recommended schedule Section 5.2)		-	NEG	NEG	IND	0	
(E) FLOATING HOSE STRING SALM								
Floating Hoses and Tail Hoses-Includes Nipples, Flanges, Seals and Bolts	1(a) Visual from launch	52	NA	NA	NA	NI	NA	
	(b) Visual from launch	365	136	0.9	NEG	50	0.4	
	2(a) Oil spill detector with launch	52	29	0.9	NEG	50		
	(b) Oil spill detector with launch	365	145	0.5	0.9	250	1.7	
	3 Visual by diver	leak detected on water	NA	NA	NA	NI	NA	
	4 Visual by diver	after storm	NA	NA	NA	NI	NA	
	5 Optical borehole	6	37	0.5	0.9	250	6.7	Evacuate hose string
	6 TV monitor on buoy (LL)	cont.	155	0.9	NEG	50	0.3	See comment page 4-2
	7 Tape detection monitored from launch	365	609	0.7	NEG	150	0.3	
	8 Dye tracing (water in hoses)	26	106	0.1	0.9	450	4	
	9 Vacuum with TV inspection pig	2	120	0.8	NEG	100	0.9	
	10 Hydrostatic	52	60	0.5	0.9	250	4.2	
	11 Acoustic array	cont.	183	0.1	0.9	450	2.5	
	12 Double walled hose	365	2100	0.1	0.9	450	0.2	
	13 Shroud with EMP pulsed coaxial cable	cont.	200	0.3	0.9	350	1.7	
	14 Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-2)			0.6	0.9	200		
	15 Water left in hoses		45	0.01	NEG	100	2.2	
	16(a) Hose string replacement	2	10700	0.5	0.9	300	0.03	
		1	5340	0.9	NEG	60	0.03	
	(b) Tail hose replacement	1/2	NA	NA	NA	NI	NA	May increase risk
		2	NA	NA	NA	NI	NA	
		3	918	0.9	NEG	30	0.03	
		4	1224	0.5	0.9	150	0.01	
Butterfly Valve	1 Visual by diver	after storm	NA	NA	NA	NI	NA	
	2 NDT (see optimized schedule Section 5.2 and Table 3-2)	-		NEG	NEG	IND	0	

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TABLE 4-2 (Continued)

OTS COMPONENT		Inspection Method or Replacement	Inspections or Replacements Freq. Year	($K)(1)	Risk Reduction Factor(2),(3),(4) Comp. Failure	System Failure	Effectiveness(6) Oil(5) Saved Barrels Oil	Cost Barrels ($K)	Comments
Blind Flange	1	Replacement	1/5	NA	NA	NA	NI	NA	
	2	NDT (see recommended schedule Section 5.2 and Table 3-2)		-	NEG	NEG	IND	0	
Other Components Anticollision blinker-lights Flanges and bolts Floatation collar Floats Brackets and bolts Gaskets and bolts Spreader bar and bolts Pickup buoy and support rope Chain	1(a)	Visual from launch	once/ship	NA	NA	NA	NI	NA	
	(b)	Visual from launch	365	-	NEG	NEG	IND	0	
	2	Visual by diver	after storm	NA	NA	NA	NI	NA	
	3	Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-2)		-	NEG	NEG	IND	0	
(F) SUBMARINE HOSE STRING - SALM									
Submarine Hoses - includes Nipples, Flanges, Seals and Bolts	1	Visual by diver to locate leaks	when oil leak detected on water	NA	NA	NA	NI	NA	
	2	Visual by diver	after storm	NA	NA	NA	NI	NA	
	3	Visual by diver using optical borehole at hose flanges-hose evacuated	6	37	0.5	NEG	50	1.4	
	4	Dye tracing with diver	26	106	0.1	NEG	90	0.9	
	5(a)	Hydrostatic (pressure drop)	after storm	NA	NA	NA	NI	NA	
	(b)	Hydrostatic (pressure drop)	52		0.3	NEG	70		
	6	Vacuum with TV inspection pig	2		0.8	NEG	60		
	7	Acoustic array	cont.	135	0.1	NEG	90	0.7	
	8	Double walled hose	52	1600	0.1	NEG	90	0.06	
	9	Shroud with EMP pulsed coaxial cable	cont.	123	0.3	NEG	70	0.6	
	10	Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-2)			0.5	NEG	50		
	11	Water left in hoses		45	0.01	NEG	20	0.5	
	12(a)	Hose replacement	1		0.9	NEG	60		
	(b)	Hose replacement	1/2	NA	NA	NA	NI	NA	
	13	3 and 10			0.3	NEG	70		
Other Components Flanges and bolts Flange seals Body floats Buoyancy tanks Brackets and bolts Gaskets and bolts	1	Visual by diver	when oil leak detected on water	NA	NA	NA	NI	NA	
	2	Visual by diver	after storm	NA	NA	NA	NI	NA	
	3	Diver NDT (see recommended schedule Section 5. 2)		-	NEG	NEG	IND	0	

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Two other inspection methods are similar in that each continuously monitors flow of oil into and out of the hose string, SPM pipeline and on the platform. One method, a flow-monitoring OTS control system (about 1% accuracy) uses conventional high accuracy flow meters to detect flow changes that are caused by large leaks or ruptures. A second method, mathematical modeling of the OTS (about 0.1% accuracy), requires measurement of various flow parameters and uses a mathematical model of the OTS components (hose elasticity, temp effects, etc.) that is programmed into a small computer. The computer can be used in conjunction with the standard supervisory control system that would be used on the platform of the DWP. This method can detect rupture and slightly lower leakage than the other method. These methods do not provide incipient failure detection.

The fourth continuously monitoring inspection method is a shroud with an EMP pulsed coaxial cable. The method has only been tested in laboratory experiments. This method requires that a shroud be placed partially around the hose string to collect oil from a leak. A special continuous coaxial cable with breaks in the outer cover which would be bridged by salt water would be installed within the shroud. A repetitive electromagnetic pulse is sent through the entire length of the cable, and depending on electrical terminations, is reflected back to the sending end. An oil leak would cause the reflected wave to be sent back inverted. The system basically is quite simple. Instruments could be placed on the deck of a ship and an alarm located at the ship. This could be done, in a like manner, on the OTS platform. The method can only provide minimal incipient failure but is capable of detecting relatively small leaks. The reliability of the method is uncertain, however, primarily because the shroud and cable must be designed to withstand rough sea states without damage. Periodic maintenance of the system would eliminate problems encountered by excessive marine growth or corrosion.

Another continuously monitoring system is in the feasibility stage and has not been satisfactorily proven in the laboratory. The method requires one to wrap the hose string in a tape that changes its electrical characteristics when oil leaks onto the inside of the tape. Detection merely requires continuous monitoring of the tape resistance either on the deck of the ship or on the platform. The method is simple and could potentially detect leaks and provide some incipient failure detection. This method is not intended for use at this time, but is included here in the event the method is developed for practical use.

Other continuously monitoring inspection methods are available but their use and oil detection sensitivity is limited somewhat by environmental conditions such as rough sea states, wave heights, wave angles, storms, dense fog, darkness, etc. Continuously monitoring oil spill detectors (see Table 3-1 and Appendices A and B), in particular, are limited by most of these environmental conditions. The detectors are capable of inspection for small leaks, but oil must float to the detectors which typically have small sensing ranges. Large arrays of sensors would solve the problem, but this approach appears impractical. These problem areas limit the spill detector's ability for early detection of rupture, but they can be used to detect leakage of small amounts of oil. Some of the devices also can discriminate between thin and thick oil films. Deck-mounted versions on a ship or launch provide an excellent aid to visual type inspections. Caution must be exercised in using detectors that may not comply with existing fire and explosion safety regulations, particularly on the deck of the ship or in the water.

Another potentially good inspection method is the combination of visual and a tape detection inspection. In the inspection method shown in Table 4-2, the tape detection scheme consists of tape wrapped around the hoses and flanges. Leaked oil will change the color of the tape. This method is in the experimental stage, but is expected to be more reliable than tapes which change in electrical resistance.

SALM Submarine Hose Strings During Offloading

Inspection methods for the SALM submarine hose strings are also given in Table 4-2. These methods have been previously described for the SALM and CALM floating hose strings not during offloading and will not be repeated here.

SALM and CALM Floating Hose String Not During Offloading

Continuously monitoring inspection methods are also an effective means of reducing the risk of oil spilled when offloadings are not in progress. This is done primarily by providing incipient failure detection before a leak occurs or detecting very small oil leaks. Since the hose strings will be left filled with a fluid (usually oil) when offloadings are not occurring, oil leak detection can still be accomplished. The acoustic arrays and the shroud with EMP pulsed coaxial cable can both provide detection of small leaks. However, only the acoustic array can also provide leak detections when the hoses are filled with seawater. Incipient failure before the leak occurs can also be accomplished by the acoustic array in the same manner as described previously. Other continuously monitoring methods, such as the OTS control system flow monitoring, mathematical modeling, TV monitoring, buoy-mounted oil spill detectors and arrays of buoy oil spill detectors, arenot considered to be sensitive to very small leaks or to provide other forms of incipient failure detection. Therefore these methods were eliminated from further consideration for this OTS operating condition.

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Some periodic inspections are very effective in reducing oil spill risks. This is because they can be used to detect very small leaks or defects and thus provide incipient failure detection.

A simple, but effective, inspection method is the use of visual inspection of a double-walled hose string. Daily visual inspections are adequate to detect any expansion of the elastic outer cover of the hoses that might occur from small incipient failure-type leaks of oil or water. Daily visual inspection is also adequate for hoses wrapped in tape that produces a color change when small oil leaks occur.

Insertion of a flexible optical borehole device with a light source can be used to provide inspection of the conditions of the inside of the hose. The device can be inserted through flanges (180^{o} apart) located at the nipple of every other hose section. By placing a vacuum on the hose string and then inspecting the hose sections, internal hose damage such as a collapsing inner liner can be observed. However, unavoidable hose flexing during inspection may cause difficulty in interpreting the inspections of some of the hose sections that are under a vacuum. This method should be particularly useful for inspecting the first hose off the CALM and the first underbuoy hose.

Another inspection method is to pull a TV inspection camera pig through the hose while it is empty, and inspect for internal hose damage. This method may be done under a vacumm, but implementation would be difficult. The hose may be damaged internally.

Using leak detection methods while the hose string is pressurized (hydrostatic tests) is a good way to find small incipient failure-type leaks. During these hydrostatic tests, the hose string can be inspected quickly and thoroughly. Large leaks can be detected merely by observing pressure drops. Using a mathematical modeling approach, somewhat smaller leaks can be detected by pressure drop methods because physical effects, such as hose elasticity, temperature, etc., are taken into account.

In cases where some oil sheen exists that may mask detection of very small leaks during hydrostatic tests, dye tracing can be very effective. Dye insertion inspections are slower than hydrostatic tests. For the simple inspection, only visual inspection of the escaping dye is required. However, for extremely sensitive inspections that provide excellent incipient failure detection, dye insertion is carried out using a different procedure. For this case, dye is first inserted into a water-filled hose string under pressure, then an adaptor is used to cover and contain fluid around a suspect hose or flange, and finally a fluorometer is used to test the fluid for minute traces of dye.

External hydrostatic inspection of the flange leaks may be effective if developed for this particular application. It is not included in Table 4-2 because it is limited only to the flanges and would not significantly reduce the spill risk. It may be used, however, as one of the recommended non-destructive tests in Section 5.1.

A variety of visual inspection schemes is shown in Table 4-2. Most of these provide no substantial improvement in risk reduction. Daily visual inspection by launch aided by the use of an electronic oil spill detector provides some improvement in incipient failure detection. This occurs because of improved reliability in detecting small leaks and in the ability of the detector to discriminate between thin (oil sheen, no leak) and thick (oil leak) oil on the water.

Visual and diver non-destructive testing for incipient failure detection carried out on a recommended schedule is given in Section 5.1. These inspections will substantially reduce oil spill risks. Inspections include methods such as seal leak detection, active ultrasonics, etc. Inspections carried out are quite extensive and will not be repeated here.

SALM Submarine Hose Strings Not During Offloading

Inspection methods for SALM submarine hose strings are also given in Table 4-2. These methods have been previously described for the SALM and CALM floating hose string not during offloading and will not be repeated here.

4.4.1.2 Effectiveness of Inspection Methods for Hose Strings

SALM and CALM Floating Hose Strings During Offloading

Risk reduction factors* achievable by purely visual observations were estimated to range from 0.5 to nearly 1.0. Such observations are judged not to be especially effective for detecting incipient failures but can detect small and large leaks. The sensitivity of the method depends in part on the location of the viewer and in part on the frequency of observation. On the other hand, the reliability of the method was judged to be negligible at night and during periods of bad weather. Thus, a risk reduction factor of 0.5 was assessed for continuous visual observation from a launch during offloading. For less frequent observation, the risk reduction factor was increased toward unity. Intermittent observation was judged to be ineffective for reducing the risk of spills from a large break (rupture), since immediate detection would not be guaranteed.

The use of an oil spill detector, especially one mounted on a launch, was judged to enhance the reliability of visual observations, especially at night. If used in a continuous mode from a launch during offloading, a risk reduction factor of 0.3 was assessed. The method was judged not as effective when not offloading since the reduced pressure within the hoses would make the existence of leaks less evident.

Replacing the on-the-scene observer with low-light TV monitors (observed in the onshore control center) was judged to be 50 percent effective, primarily for the instantaneous detection of ruptures. Again, the effective use of this method is limited to relatively good weather but can be used advantageously at night.

Presently, no detailed monitoring of the flow of oil into and out of the hose string (and the SPM unit and SPM pipeline) is performed. Use of such a system capable of detecting a one percent

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* A risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14).

difference in the flows is judged to be very effective for the instantaneous detection of the large leaks and ruptures during offloading. Improving the sensitivity to 0.1 percent was judged to effect only a marginal increase in the reduction of risk. The reason for this is that at these levels of sensitivity the frequent small leaks remain undetected. Moreover, the method would not give an indication of incipient failures.

The use of buoy-mounted oil spill detectors during offloading was judged not to be especially effective and was given a risk reduction factor of 0.9. The reason for this is that, depending on the direction of the wind and current, a leak of oil and even the loss of oil from a rupture, could miss the buoy and not be detected. In order to counteract this problem, a large number of buoys could be used. However, it is unlikely that this would be done since they would interfere with normal operations at the SPM.

Tape detection of leaks in conjunction with regular inspection from a launch was judged to be especially effective for small leaks and incipient failures which are manifested as small leaks. A double walled hose is at least as effective as the tape since the oil from most leaks would be trapped by the second wall. For either method, if observed continuously from a launch, means would then be available to give immediate detection of a large break or rupture during offloading. For all of these uses, a risk reduction factor of 0.1 was assigned.

An acoustic passive array was judged to be effective during offloading, both for detecting leaks and incipient failure, and for giving immediate warning of a large break or rupture. As an added advantage over the above methods, the output of the array can be monitored remotely. A risk reduction factor of 0.1 was estimated for this method. The EMP pulsed coaxial cable detection method was judged to be slightly less effective, having a risk reduction factor of 0.3. The reason for this is that oil must leak and must accumulate inside the shroud before detection can occur.

SALM Underwater Hose Strings

Except for the methods requiring visual observation from a launch, all of the above methods were judged to be equally effective for the underwater portion of the SALM hose strings. These include the acoustic array, EMP pulsed coaxial cable, buoy oil spill detector and the control system monitors. Visual observation from above the water surface or from a launch was judged to be ineffective, a risk reduction factor of 0.9.

Hose Strings Not During Offloading

Several methods not only may be effective for detecting leaks during period of hose idleness, but also, and more importantly, for providing means of detecting incipient failures. Non-destructive testing by a diver twice a year was judged to provide a risk reduction factor of 0.5 for leaks and incipient failures. A greater risk reduction could be achieved by more frequent and more thorough inspections with NDT. In this vein, adding the optical borehole method together with an applied vacuum allows a visual inspection of portions of the interior of the hoses. A risk reduction factor of 0.5 was estimated for this combination. Interior inspection also could be accomplished with a pig (twice a year); but this alone was judged to give a risk reduction factor of only 0.8.

Pressurizing the hose string and searching for leaks of oil (once a week) was estimated to give a risk reduction of 0.5, on the basis that incipient leaks would tend to develop into detectable leaks when the hose is stressed to levels above those at operating conditions. Using a dye was judged to increase the sensitivity of this process and a risk reduction factor of 0.1 was estimated.

Leaving the hoses filled with water rather than oil between ship calls would be highly effective in limiting the risk of oil spills during these periods, but is not useful for detecting leaks except for the acoustic array inspection method which can detect either oil or water leaks.

Under the assumption that the hose strings are pressurized and are left full of oil during periods of idleness, many of the methods used to detect leaks during periods of offloading also are effective to the same degree. These include the passive acoustic array, the EMP pulsed coaxial cable and frequent visual observation.

As an alternative to inspection, the entire hose string or portions of it could be replaced during periods of idleness. This is done at regular intervals ranging from 6 to 48 months at most DWPs.* Actual hose replacement schedules depend on the amount of usage and environmental conditions. More frequent hose replacement could reduce spill risk. However, the extent of the reduction is limited because of possible errors made during assembly such as too rough handling and faulty flange connections. Moreover, the replacement hose itself may be defective. There are insufficient data to make a quantitative determination of these factors. For this study, the risk reduction achievable either by regular hose replacement or bringing the hose onshore to ascertain its suitability for use at intervals exceeding 12 months was assumed to be nil. For intervals of 12 months or less risk reduction factors were improved. Tail hoses and the first hose off the CALM were assumed to require more frequent replacement. Hose replacement is particularly important during the first few years of operation when effects of environmental conditions are uncertain.

<u>Effectiveness- Reduced Barrels of Oil Spilled</u>

Of the rupture total, 10 percent was assumed to result from hose deterioration and to be preventable by effective detection of incipient failures. The other 90 percent arises from other causes such as ship breakout (failure of the mooring hawsers) and is unaffected by inspection of the hoses.

For the SALM hose strings, leak and rupture failure risk was assumed to be divided between the floating and underwater portions, in the ratio of 6 to 1 (6 submarine and 30 floating hose sections). Some examples are given below to illustrate how specific reductions in oil spill risk were computed.

The barrels of oil not spilled as a result of the application of an inspection method was based on the following risk values derived from Table 3-14 of Reference 1. During offloading, the total risk of large spills or ruptures is 2,900 bbls/year and the risk of leaks is 310 bbls. The

* At one deepwater port in Europe, local regulations require hose removal and inspection every 6 months and hose rejection after 12 months.

rupture total is divided into two parts: that lost during the time required to detect the rupture, 1000 bbls/year, and that lost during shutdown of the oil flow plus the oil remaining in the hoses, 1900 bbls/year (see pp. 3-67 and 3-68 of Reference 1). Hence, immediate detection of ruptures (e.g., by 100 percent effective continuous visual observation) would reduce the rupture risk by 1000 bbls/year.

For the CALM hose string during offloading, the risk reduction factor for continuous inspection from the launch is 0.5. The method is applicable for detecting leaks, incipient ruptures and instantaneous detection of ruptures. Hence, the reduced volume of oil spilled is : (1-0.5) [310 (leaks) + 1000 (rupture detection) + 290 (incipient rupture)] = 800 bbls/year. The system effectiveness is defined as the spill volume reduction divided by the total risk, which in this case is 3210 bbls/year, 310 bbls/year (from leaks) plus 2900 bbls/year (from ruptures):

$$\frac{(3210 - 800)\ \text{bbls/year}}{3210\ \text{bbls/year}} = 0.8.$$

Visual inspection from the launch made every two hours are ineffective for immediate rupture detection, but are modestly effective for detection of leaks and incipient failures, a risk reduction factor of 0.7. Hence, the reduction in barrels spilled is: (1-0.7)[310 (leaks) + 290 (incipient rupture)] = 180 bbls/year. The system effectiveness is:

$$\frac{(3210 - 180)\ \text{bbls/year}}{3210\ \text{bbls/year}} = 0.9.$$

For the passive acoustic array, the risk reduction factor is 0.1 and the reduced volume spilled is:

(1-0.1)[310 (leaks) + 1000 (rupture detection) + 290 (incipient rupture)] = 1440 bbls/year.

The system effectiveness is:

$$\frac{(3210 - 1440)\ \text{bbls/year}}{3210\ \text{bbls/year}} = 0.5.$$

The other values listed in Table 4.2 were calculated in a similar manner.

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4.4.2 Mooring System

4.4.2.1 Preliminary Selection of Inspection Methods

Failure of the mooring system during offloading can cause ship breakout and result in rupture of the floating hose string. This failure, as shown in Section 3 of Reference 1, results in the highest oil spill risk (see Table 4-1) because it is the major cause of floating hose string rupture. Failure of the mooring hawsers is the primary failure of the mooring system. Often two hawsers are used and each is typically 200 feet long, 15 inches in diameter, made of braided nylon and capable of sustaining the mooring strain. Other mooring system components are described in Section 3.2. Although the relative risk of oil spills for the mooring system is quite high, there exist only a few new inspection methods for the risk reduction analysis (these new methods were not in use during the time period that was used for the risk data). Selected inspection methods are given with inspection intervals, estimated costs, risk reduction factors and effectiveness in Table 4-3. Selected inspection methods for the specific components of the mooring system are identified in Table 3-2.

A good approach for reducing the oil spills resulting from the failure of mooring systems is to continuously monitor the mooring system during offloading using inspection methods that can provide both incipient failure detection and immediate detection of mooring system failure. One inspection method, a buoy strain-gage load monitor (Reference 35) is commercially available (see Appendix A). The system can be installed either on a SALM or CALM buoy and can continuously measure the mooring line loads. The device can be used to reduce oil spill risks in three main ways: 1) detects ship breakout instantaneously; 2) provides incipient failure detection by giving an alarm when tanker loads reach unsafe levels; ship offloading can be stopped until the loads become safe; 3) provides incipient failure detection by monitoring historical data on rope fatigue. In addition, the telemetry system used with the inspection method can accommodate other continuously monitoring inspection methods or sensors

TABLE 4-3 COST-EFFECTIVENESS ANALYSIS FOR MOORING SYSTEM

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements: Freq. Year	Inspections or Replacements: ($K)(1)	Risk Reduction Factor (2),(3),(4): Comp. Failure	Risk Reduction Factor (2),(3),(4): System Failure	Effectiveness Oil(5) Saved: Barrels Oil	Effectiveness Cost: Barrels ($K)	Comments
MOORING SYSTEM DURING OFFLOADING								
Hawser, chaffing chain, buoy chain	1(a) Visual by launch	once/ship	NA	NA	NA	NI	NA	
	(b) Visual by launch	once/2hrs	-	NEG	NEG	IND	0	
	(c) Visual by launch	Cont.	435	0.1	0.7	810	1.9	
	2 Visual on deck of ship*	Cont.	316	0.5	0.5	450	1.4	
	3 Visual on CALM	Cont.	316	0.1	0.7	810	2.6	
	4 TV monitor on buoy	Cont.	178	0.5	0.9	450	2.5	Impractical for SALM
	5 Acoustic array	Cont.	118	0.4	0.5	1560	13	
	6(a) Mooring load monitor	Cont.	110	0.3	0.4	1820	16	
	(b) Mooring load monitor	12	140	0.25	0.3	1950	14	External loading calibrations using scheduled loading sequence
	7 5 and 6 (b)	Cont.	185	0.1	0.2	2340	13	
Other Components Pickup rope Floats Chain support buoy and connection linkage	1 Visual by launch	once/ship	NA	NA	NA	NI	NA	
	2 Visual on deck of ship	Cont.	NA	NA	NA	NI	NA	
MOORING SYSTEM NOT DURING OFFLOADING								
Hawsers, chaffing chain, buoy chain	1 Visual by launch	52	NA	NA	NA	NI	NA	
	2 Diver visual inspections	12	NA	NA	NA	NI	NA	
	3 Acoustic array - external load calibrations	52	150	0.2	0.3	2080	14	External loading cali. using increased load. ea. mo.
	4 Diver NDT (see recommended schedule-Section 5.2 and Table 3-2)			0.4	0.5	1560		
	5 Replace hawser	2	NA	NA	NA	NI	NA	
		3	300	0.8	0.8	870	2.9	
		4	400	0.5	0.5	1200	3	
		6	600	0.3	0.3	1730	2.7	
		12	1200	0.2	0.2	2200	1	
	6 Replace chaffing chain	1/5	NA	NA	NA	NI	NA	
	7 Replace buoy chain	1/5	NA	NA	NA	NI	NA	
Other Components Pickup rope Floats Chain support buoy and connection linkage	1 Visual by launch	52	NA	NA	NA	NI	NA	
	2 Diver visual inspections		NA	NA	NA	NI	NA	
	3 Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-2)		-	NEG	NEG	IND	0	

NOTE:
(1) Inspection or replacement cost estimates based on yearly costs amortized over a ten-year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14. Risk reduction factor is estimated for the component (if appropriate, also for indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section 3.
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.
* Assumes visual inspection on deck of ship was carried out on a partial basis during time period when data were used for determination of risks in Section 3 of Reference 1.

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that may be used at or near the buoy. Caution is advised in using this system to extend the life of the hawsers. If this is done, cost savings of hawser replacement occur but oil spill risks may not improve and, in fact, may get worse. Monthly or bi-monthly calibration of the load monitor inspection system and mooring line using scheduled loading sequence (similar to what is done in wind tunnels, for example) is highly desirable. This would improve both the reliability of the system and provide load history calibrations of the mooring line that would improve the interpretation of the mooring line condition. Calibrations can be computerized, at a nominal cost; this would significantly reduce interpretations of mooring line condition by operating personnel.

A continuously monitoring acoustic emission inspection system also appears to have excellent potential for reducing oil spill risks. The system is not commercially available but would be similar to the mooring load monitor system. It could be installed either on the CALM or SALM mooring buoy and could be used in the following ways: 1) detects ship breakout instantaneously; 2) provides incipient failure detection of the mooring line by detecting when the mooring line is approaching an unsafe condition. The line would thus be inspected and/or replaced. The unsafe condition is detected when the rate of acoustic emission reaches an unsafe level. The unsafe level would have to be predetermined in the laboratory on a sufficient number of representative test samples; 3) provides incipient failure detection of the mooring line by monitoring historical acoustic emission data from external loads. External loading calibrations, using an increased loading schedule on possibly a weekly schedule is highly desirable. This could improve the reliability of the system and provide load history calibrations of the mooring line that would improve interpretation of the mooring line condition. Calibrations can be computerized, at a nominal cost; this would significantly reduce interpretation of mooring line condition by operating personnel. The main problem with this inspection method is that although incipient failure acoustic emission profiles prior to ship breakout would follow normal incipient failure

profiles, some interpretation is required concerning amount of time before failure occurs. Nevertheless, there would be sufficient time to detect a catastrophic failure and stop unloading. This inspection method also is capable of providing the location of the specific areas where defects are appearing. NDT methods could be used to more closely inspect those areas. Acoustic monitoring has not been applied to mooring lines but has been used successfully in similar types of applications (see Reference 45). The acoustic monitoring system would require that extensive laboratory testing be carried out on mooring line components before a reliable system could be implemented. Most system components such as the sensors, data acquisition system, computer and telemetry systems, however, are commercially available.

The combinations of the mooring load monitor system and the acoustic array would potentially provide extremely high sensitivity and reliability. Use of both systems may allow extended use of the mooring system and may actually provide cost savings by reducing hawser replacement. Other less effective inspection methods of the mooring system are available during offloading. These are mainly visual inspections from the deck of the ship, on the monobuoy, on the platform or from a launch. A low-light TV monitor can be used on the deck of the ship or on the buoy to aid visual inspection. Visual inspection can also be carried out from a launch when a ship is not moored to the buoy. The specific inspections that can be carried out are given in Appendix B and those recommended are included in Section 5.1.

Effective visual and NDT inspections on mooring system OTS components can be accomplished using a diver and a launch when a ship is not moored to the buoy. Specific diver visual inspections are given in Appendix B and recommended ones are included in Section 5.1. NDT inspections can provide good incipient failure detection if the inspections are scheduled at frequent intervals. Particularly effective NDT inspection methods include: measurement of the length of the mooring hawser; X-ray inspections of the mooring hawser, chains, brackets, etc.; penetrant inspections of the chains; magnetic rubber inspection of the chains.

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Replacement of the hawsers, chaffing chain, buoy chain and brackets at frequent intervals will reduce oil spill risks. In some instances this may be more desirable than inspections because of lower cost or simplicity.

4.4.2.2 Estimation of Risk Reduction Achievable by Inspection of the Mooring System

Ship breakout because of the failure of the mooring system, especially the hawsers, is a primary cause of the rupture of the floating hose strings during offloading. Continuous visual observation of the hawser from almost any vantage point will allow immediate detection of hawser failure and hence immediate initiation of the shutdown of oil transfer even though rupture of the hoses and loss of oil cannot be prevented. The risk reduction factor* estimated for this method is 0.5 from the deck of a ship because it is assumed that some visual inspections were carried out on a part-time basis when risks were determined.

The use of a low-light TV monitor rather than an on-the-scene observer is judged to be approximately as reliable as the latter; a risk reduction factor of 0.5 was assessed.

Continuous monitoring by an acoustic array was judged to have a risk reduction factor of 0.4 with respect to detecting incipient failures of the hawser and preventing ship breakout. Similarly, a strain-gage load monitor on the hawser is estimated to have a risk reduction factor of 0.3. This estimate is based primarily on the sensor's ability to sense and count loadings which equal or exceed the elastic limit of the hawser. Calibrating the gage once a month is expected to improve the reliability of the method; a risk reduction factor of 0.25 is estimated for this case. The highest sensitivity and reliability is estimated for the combination of an acoustic array and the strain-gage load monitor. A risk reduction factor of 0.1 is estimated. This combination allows continuous monitoring of the response of the hawser to each loading and comparisons can be made at equal loading to determine deterioration.

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*The risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14).

When a ship is not moored, several non-destructive tests may be applied to the hawser. Also, the response of hawser to a set of prescribed loads may be determined with an acoustic array. Risk reduction factors of 0.3 and 0.2 were estimated for these, respectively. Alternatively, the hawsers and the other components of the mooring system could be replaced periodically. By this method it was estimated that a risk reduction factor of 0.5 could be achieved by replacing the hawser at least every three months.

Estimation of the reduction in the barrels of oil spilled was based on the risk value of 2600 bbls/year from hose rupture caused by mooring system failure (see Section 4.4.1.2). Thus, for the mooring load monitor method alone during offloading the reduced risk of barrels of oil spilled is

$$(1\text{-}0.3)\left[2600\,(\text{rupture prevention})\right] = 1820 \text{ bbls/year.}$$

The system effectiveness is

$$\frac{(3200 - 1820)\text{bbls/year}}{3200 \text{ bbls/year}} = 0.4,$$

where it may be recalled that 3200 bbls/year is the total spill risk from hoses during offloading (see Section 4.4.1.2). In the case of visual observation the maximum spill risk reduction is 900 bbls/year, since only immediate detection of the rupture is possible (see Section 4.4.1.2). Thus, the reduced risk of barrels of oil spilled is

$$(1\text{-}0.1)\ [900\ (\text{rupture detection})] = 810 \text{ bbls/year.}$$

The system effectiveness is

$$\frac{(3200 - 810)\text{bbls/year}}{3200 \text{ bbls/year}} = 0.7.$$

4.4.3 Shipboard Connections

4.4.3.1 Preliminary Selection of Inspection Methods

Existing inspections of the shipboard connections of the OTS appear to be adequate because only a small oil spill risk (50 barrels/year) is expected to occur (see Table 4-1).

These existing inspection methods are selected and shown in Table 4-4 and also noted in Table 3-2. Other selected inspection methods which may be useful and can be used at the discretion of the ship owner or operator are also indicated.

4.4.3.2 Estimation of Risk Reduction Achievable by Inspection of Shipboard Connections

Oil spill risks for shipboard connections can not be appreciably improved because this method has been in general use. Hence, effectiveness values were not computed.

4.4.4 Undersea Pipeline

4.4.4.1 Preliminary Selection of Inspection Methods

One of the major sources of potential deepwater port oil spillage is caused by undersea pipelines. This is apparent from the results given in Section 3 of Reference 1 and those shown in Table 4-1. In addition, one study (Reference 46) indicates that pipeline failures occurring in areas such as the Gulf of Mexico appear to be increasing. Pipelines expected to be used are three undersea lines 56 inches-OD that are about 21 miles long and buried 3 feet and also six SPM pipelines 48 inches-OD, each about 8000 feet long and buried about 10 feet. A number of inspection methods were selected for further evaluation for the following reasons: 1) high spill risk, 2) increasing pipeline failures, 3) information presented in previous sections and 4) the availability of many suitable inspection methods. The selected inspection methods are shown with inspection intervals, estimated costs, risk reduction factors and effectiveness in Table 4-5. These methods are also noted in Table 3-3 for specific OTS undersea pipeline failure modes.

Undersea pipeline rupture is the major source of oil leakage in the pipeline primarily because of the large volume of oil that can be spilled. Inspections can be carried out that may reduce significantly the frequency of rupture. A major cause of pipeline rupture is external impacts from objects such as anchor dragging. A general periodic survey can be carried out to reduce the frequency of rupture by inspecting the pipeline for bare spots, the depth of soil

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TABLE 4-4 COST-EFFECTIVENESS ANALYSIS FOR SHIPBOARD CONNECTIONS

OTS COMPONENT	Inspection Method * or Replacement	Inspections or Replacements Freq. Year	Inspections or Replacements ($K) (1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	Risk Reduction Factor (2),(3),(4) System Failure	Effectiveness (6) Oil (5) Saved Barrels Oil	Effectiveness (6) Cost Barrels ($K)	Comments
SHIPBOARD CONNECTIONS								
Ship Manifold Expansion Joint	1 Visual on deck	cont.	NA	NA	NA	NI	NA	
	2* Hydrostatic							
	3* Passive acoustic							
	4* NDT (see Table 3-2)							
Ship Manifold	1 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	2* Hydrostatic							
	3* Passive acoustic							
	4* Seal leak detector							
	5* NDT (see Table 3-2)							
Gasket Between Hose Flange and Manifold	1 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	2* Hydrostatic							
	3* Seal leak detector							
	4* NDT (see Table 3-2)							
Ship Manifold Valve	1 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	
	2* Hydrostatic							
	3* Operational checks							
	4* NDT (see Table 3-2)							
Drip Tank and Scuppers	1 Visual on deck of ship	cont.	NA	NA	NA	NI	NA	

NOTE: (1) Inspection or replacement cost estimates based on yearly costs amortized over a ten-year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14). Risk reduction factor is estimated for the component (if appropriate, also indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section 3.
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.
* Methods available at discretion of ship owner.

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TABLE 4-5 COST-EFFECTIVENESS ANALYSIS FOR UNDERSEA PIPELINE

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements Freq. Year	Inspections or Replacements ($K)(1)	Risk Reduction Factor (2),(3),(4) Failure Mode	Risk Reduction Factor (2),(3),(4) System Failure	Effectiveness(6) Oil (5) Saved Barrels Oil	Effectiveness(6) Cost Barrels ($K)	Comments
(A) UNDERSEA PIPELINE								
Rupture	1(a) Visual (helicopter, etc.)	365						
	(b) Visual (helicopter, etc.)	26	NA	NA	NA	NI	NI	
	2 Buoy oil spill detectors	cont.		NEG	NEG	IND		
	3 Dye tracing-for location	when leak	NA	NA	NA	NI	NA	After leak detected
	4(a) Inspection pig	2	250*	0.5	0.7	300	1.2	
	4(b) Inspection pig-3d(UI)	2	350*	0.1	0.5	560	1.6	Ultrasonic imaging
	5 Hydrostatic(pressure drop)	1	6	0.9	NEG	100	16	Assumes leak detection
	6 Reflected pressure wave	1	-	NEG	NEG	IND	0	
	7 Sonar-sidescan and penetration	6	42	0.5	0.7	360	7.5	
	8 Mapping	12	40	NEG	NEG	40	1	
	9 Hydrocarbon probe	6	30	0.9	NEG	60	3	
	10 OTS control system 1% accuracy	cont.	NA	NA	NA	NI	NA	
	11 OTS control system 0.1% accuracy	cont.	20	0.5	0.5	500	25	
	12 Acoustic array	cont.	300	0.1	0.1	900	3	
	13 Shroud with EMP pulsed coaxial cable	cont.	166	0.3	0.6	420	2.5	
	14 Corrosion-flow sampling program	26		0.9	0.9	60		
	15 5 and 12	1	306	0.5	0.7	300	1	
Corrosion	1 Inspection pig	2	250*	0.1	NEG	15	< 0.1	
	2 Corrosion-flow sampling program	26		0.5	NEG	8		
	3 Hydrostatic(pressure drop)	1	6	0.5	NEG	8	1.2	
	4 Acoustic array	cont.	-	0.1	NEG	15	< 0.1	
	5 Hydrocarbon probe	6	30	0.5	NEG	8	0.3	
	6 3 and 4	1	11	0.08	NEG	20	2	
	7 Passive ultrasonic	6	7	0.8	NEG	3	0.4	
Welds	1 Inspection pig	2	250*	0.1	NEG	15	< 0.1	
	2 Hydrostatic(pressure drop)	1	6	0.5	NEG	8	1.2	
	3 Hydrocarbon probe	6	30	0.5	NEG	8	0.3	
	4 Acoustic array	cont.	300	0.1	NEG	15	< 0.1	
	5 2 and 4	1	306	0.08	NEG	20	< 0.1	
	6 Passive ultrasonic	6	7	0.8	NEG	3	0.4	
Cathodic Protection	1 Mfg. inspection schedule and maintenance	1	NA	NA	NA	NI	0	

NOTE: (1) Inspection or replacement cost estimates based on yearly costs amortized over a ten-year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14. Risk reduction factor is estimated for the component (if appropriate, also indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section 3.
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.
* Costs are uncertain because no inspection pigs are available for 54-inch diameter pipelines. Higher rental or service costs may be required to help defray commercial costs of building an inspection pig for such limited usage.

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above the pipeline and by mapping the pipeline location. Thus if the pipeline is unprotected by soil coverage or poorly supported because of scour, immediate coverage of unprotected areas can be carried out. The general survey could consist of inspecting the pipeline a number of times a year with a towed fish that contains both a side-scan sensor for detecting bare spots and a penetrating sonar with standard echo to measure overburden. If either bare spots or unsafe soil levels are detected, a standard survey with a submersible or remotely piloted vehicle could be used to look more closely at questionable areas. Then, if needed, diver inspection of the pipeline using non-destructive testing or special methods for detection of external damage, corrosion, defective welds and cathodic inspections can be carried out. A general survey can potentially be carried out by an ultrasonic imaging inspection pig [currently under development - Table 3 Part 3.2.1(g)] if the device were modified to include depth of soil and pipeline bare spot inspection. A continuously monitoring acoustic system could be used to detect and locate external impacts such as anchor dragging that occur before rupture.

Other approaches are either to detect the location of a leak, before it grows to a critical size and causes a catastrophic failure, or to detect and locate the rupture quickly in order to shut the system down so repair of the leak, containment and removal of the oil spilled can be carried out. Continuously monitoring systems that are permanently installed, such as the acoustic array or shroud with an EMP pulsed coaxial cable, could be used to immediately detect and locate small leaks or ruptures. A highly accurate (0.1%) continuously monitoring control system that uses a mathematical modeling approach and requires the monitoring of various parameters of the input, output and at various locations along the pipeline can be effective in detecting ruptures or detecting medium-sized leaks that may lead to rupture. A conventional, accurate (1%) OTS control system that continuously monitors flow, pressure and volume at the input and output of the pipeline would be much less sensitive but could detect rupture. Neither type of control system

could provide the location of rupture so that leak location methods would be required. Inspection pigs can be effective in detecting and locating small leaks or defective areas that can lead to rupture. They must be periodically sent through the pipeline. An ultrasonic-imaging type inspection pig currently under development, if successful, will considerably improve the effectiveness of pipeline inspection. Cost considerations generally prevent enough frequent pig inspections to provide optimum incipient failure detection. A large array of continuously monitoring buoy oil-spill detectors (currently only in situ-type are available but unproven in DWP environment) can be used to detect and locate small leaks or to detect rupture only after they occur. Considering the large length of pipeline, ocean currents, etc., the probability of detecting small leaks or quickly detecting ruptures is quite low. However, an array of buoy oil-spill detectors each with wide inspection area coverage would be very effective. These wide areas buoy detectors (scanning type) are only in the feasibility stage. Their effectiveness may be a considerable improvement over that of other detectors, but development and detector costs may be too high from a cost-effectiveness viewpoint. Other methods currently available may be more cost-effective. They may, however, warrant considerations as backup or redundant detection systems. Periodic surveys using a towed fish instrumented with a hydrocarbon sniffing probe can be used for detection and location of small leaks. Less effective techniques include the following: hydrostatic tests; a passive acoustic sensor hand held by a diver or installed in a towed fish to locate the sounds emitted from a small leak (this method may be useful in locating a known rupture); dye insertion into the pipeline; reflected pressure wave; corrosion flow sampling program. Visual inspections by air from helicopters, etc., for detection of bubbles or oil can be carried out but would provide little or no detection of small leaks and can not be carried out often enough to provide sufficient time to prevent a major spill. Night inspections would be very difficult unless visual inspections were supplemented by very costly remote sensing methods.

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A double walled pipe could greatly reduce rupture and could provide easy detection of leakage, but the costs for a long pipeline would be obviously too high for practical implementation.

Yearly hydrostatic testing when used with the acoustic array (see Reference 5) provides a much greater improvement in incipient failure detection. This occurs because the acoustic array can detect and locate flaws by monitoring acoustic emission signals generaged from flawed areas in the pipeline when the stress levels in the pipeline are increased. In addition, acoustical sounds generated from small leaks at high pressure can be detected. These leaking areas may not be detectable at normal operating conditions. Undersea hydrostatic testing is not normally very effective because leak sources are very difficult to detect and small leaks along the pipeline cannot be detected by conventional pressure-monitoring methods. There is some concern by pipeline operators that a hydrostatic test may cause rupture. This may be true for older pipelines or in cases where excessive hydrostatic pressures are applied. However, the risk is extremely low for new pipelines at reasonable hydrostatic pressures.

Corrosion and defective welds are identified in Reference 1 and Table 4-1 as the cause of a high frequency of low volume oil-spill incidents. Periodic inspections using inspection pigs (primarily magnetic flux-type with TV camera or passive acoustic with TV camera) appear to be one of the better ways of providing incipient failure detection. Hydrostatic tests which monitor the pressure drop are simple and provide some incipient failure detection. A corrosion flow-sampling program also appears to provide some incipient failure detection, but the method generally can only provide corrosion trends in the pipeline. A towed fish with a hydrocarbon probe appears to be useful in detecting and locating the small leaks that occur from weld or corrosion defects. However, the inspection must be carried out frequently to be very effective. A continuously monitoring passive acoustic array can provide some incipient failure detection because sufficiently large leaks can be detected and located. Inspections by divers or divers in submersibles similar to those described previously must be carried out when a leak or other incipient failure is detected.

Cathodic protection inspection should be carried out using manufacturer recommended inspection schedules. Methods typically used would include measurement of electric potentials, electric continuity, measurement of anodes for the amount of wastes, visual examination, photographs and the noting of corrosion and marine growth.

4.4.4.2 Estimation of Risk Reduction A-hievable by Inspection of Undersea Pipelines

Rupture of the undersea pipelines can result both from deterioration and from "third party" damage. The latter can be largely prevented by maintaining a sufficient depth of soil over the pipeline. Sonar techniques, sidescour and penetrating, and mapping the pipeline could help detect the loss of soil cover via erosion or scour. The former techniques utilized in a bimonthly survey for this purpose were judged to have a risk reduction factor* of 0.1 whereas, the mapping technique was judged to have a risk reduction factor of only 0.9.

Neither a control system capable of monitoring the flow to an accuracy of 1 percent, nor a system supplemented with mathematical analysis were judged to give large reductions in risk. The reason for this is that they can detect only the loss of a relatively large amounts of oil after the rupture has occurred. Risk reduction factors of 0.9 and 0.5 were assessed for the former and latter systems, respectively.

Three methods listed in Table 4.5 are capable of detecting incipient failures occuring because of deterioration. A risk reduction factor of 0.3 was assessed for the EMP pulsed coaxial cable and a factor of 0.9 was assessed for an inspection pig used twice a year. A greater reduction in risk, a risk reduction factor of 0.1, was assessed for the passive acoustic array. The reason for this is its ability to immediately detect and locate "third party" damage (e.g., a dragging anchor) to the pipeline.

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*The risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14).

Yearly hydrostatic testing of the pipeline was judged to be capable of detecting incipient failure effectively. However, if used with an acoustic array a much greater effectiveness can be achieved since the pipelines response to changes in stress levels can be monitored and located. The risk reduction for these two methods is 0.5 and 0.1, respectively.

Leaks caused by corrosion and by the failure of welded seams and joints can be detected at early stages by a number of techniques. For these purposes risk reduction factors were assessed as indicated in Table 4.5 for the following methods: inspection pig, twice yearly, for both corrosion and welds; sampling for corrosion products in the flow; passive acoustic array for both types of leaks; hydrostatic tests of the pipeline once a year; hydrocarbon probe; hydrostatic tests with passive acoustic array, passive ultrasonics.

The estimations of the reduced volumes of oil spilled were based on the following data. From Table 3.14 of Reference 1, ruptures of the pipeline contribute a risk of 1,000 bbls/year and leaks contribute 34 bbls/year. Further, it was assumed that 40 percent, 400 bbls/year, of the rupture risk is caused by "third party" damage and the remainder, 600 bbls/year, is caused by deterioration (Section 3.2, Reference 1). As an example of the calculation of reduced volumes of oil spilled, the sonar techniques affect only the possible rupture by "third party" activities, and the result is:

$$(1-0.1)\ [400\ \text{(rupture damage)}] = 360\ \text{bbls/year.}$$

The system risk reduction factor is:

$$\frac{1034-360}{1034} = 0.7.$$

For another example, the passive acoustic array was judged to be effective for all types of ruptures and hence the reduced oil spill risk is

$$(1-0.1)\ [1000\ \text{(all ruptures)}] = 900\ \text{bbls/year.}$$

The system risk reduction factor is

$$\frac{1034-900}{1034} = 0.1.$$

4.4.5 SALM SPM

4.4.5.1 Preliminary Selection of Inspection Methods

Oil spills (Table 4-1) occur frequently for the SALM SPM unit, but actual oil spill risks are small, only about 30 barrels per year according to Section 3 of Reference 1 because the nominal size of each spill is small. The spill data are based upon the use of 6 SPMs (see Section 3.4) for either of two types of operation:

(1) Each SPM is used in sequence and the time each ship is berthed is 20-24 hours;

(2) Four SPMs are regularly used and 2 are used during emergencies or during repair of the other 4.

Water depth is expected to be less than 150 feet. The oil leaks (Fault Tree C in Reference 1) are expected to occur primarily from ship collision and seals of the liquid swivel assembly. Minor sources of leaks include the PLEM, valves and piping. A major source of oil spill risk, about 150 barrels per year (included as part of "hose strings during off-loading, ruptures", in Table 4-1), occurs via the failure of the SALM's mooring system, ship breakout and then hose rupture. Although this event is infrequent (about 0.02 per year), the oil spill risk is high because of hose rupture. Based upon the information presented here and in previous sections, only a few inspection methods were selected. Table 4-6 shows the selection inspection methods with inspection interval, estimated costs, risk reduction factors and effectiveness. Selected inspection methods for specific SALM components are noted in Table 3-4.

The most effective inspections of the SALM SPM are diver visual and NDT inspections (see Table 3-4 and Section 5.1) carried out on the external structure from the mooring buoy to the PLEM.

TABLE 4-6 COST-EFFECTIVENESS ANALYSIS FOR SALM SPM

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements		Risk Reduction Factor (2),(3),(4)		Effectiveness (6) Oil(5) Saved	Cost	Comments
		Freq. Year	($K)(1)	Comp. Failure	System Failure	Barrels Oil	Barrels ($K)	
(A) MOORING BUOY								
External Structure	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
Navigation light	(b) Visual by diver	1	NA	NA	NA	NI	NA	
Hull	2(a) Visual on buoy	after storm	NA	NA	NA	NI	NA	
Fenders	(b) Visual on buoy	72	NA	NA	NA	NI	NA	
Buoy anodes	3(a) Buoy position	after storm	-	NEG	NEG	IND	0	Check buoy position
Mooring bracket	(b) Buoy position	12	-	NEG	NEG	IND	0	Check buoy position
Center shaft extension	4 Acoustic array	cont.	-	NEG	NEG	IND	0	
	5 Mfg. recommended maintenance and inspections		NA	NA	NA	NI	NA	
	6 Diver visual and NDT (see recommended schedule Section 5.2 and Table 3-4)		25	0.1	NEG	140		
Internal Structure	1(a) Visual on buoy	after storm	NA	NA	NA	NI	NA	
Buoy body compartment	(b) Visual on buoy	12	NA	NA	NA	NI	NA	
Pins Fog signal Bolts	2 Visual and NDT (see recommended schedule Section 5.2 and Table 3-4)		-	0.3	NEG	IND	0	
Brackets	3 Mfg. inspections and maintenance recommendations		NA	NA	NA	NI	NA	
(B) FLUID SWIVEL								
Attachment eye Housing Split clamp ring Joints	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
	(b) Visual by diver	after leaks detected on water	NA	NA	NA	NI	NA	
Gaskets	2 Dye tracing	6	37	0.5	0.7	8	0.22	
Seals	3(a) Hydrostatic(Pressure drop)	after storm		NA	NA	NI	NA	
Bearings	(b) Hydrostatic(pressure drop)	52	-	NEG	NEG	IND	0	
Brackets	4 Acoustic array	cont.	-	NEG	NEG	IND	0	
Bolts	5 Shroud with EMP pulsed coaxial cable	cont.	-	NEG	NEG	IND	0	
	6 Diver NDT and visual (see Section 5.2 and Table 3-4)	2	18	0.5	NEG	8	0.4	Includes seal leak detection and teltale inspection
	7 Mfg. inspections and maintenance recommendations		NA	NA	NA	NI	NA	
(C) HOSE ARM								
Hose arm assembly Valve Hose connections Buoyancy tanks	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
	(b) Visual by diver	after leaks detected on water	NA	NA	NA	NI	NA	
Resilient bumpers	2 Dye tracing	6	37	0.5	0.7	8	0.2	
Brackets	3(a) Hydrostatic(Pressure drop)	after storm	NA	NA	NA	NI	NA	
Bolts	(b) Hydrostatic(Pressure drop)	52	NA	NA	NA	NI	NA	
Seal	4 Acoustic array	cont.	-	NEG	NEG	IND	0	
	5 Shroud with EMP pulsed coxial cable	cont.	-	NEG	NEG	IND	0	
	6 Diver NDT and visual(see Section 5.2 and Table 3-4)		15	0.5	0.7	8	0.4	Includes seal leak detection and teltale inspection
	7 Mfg inspection and maintenance recommendations		NA	NA	NA	NI	NA	

NOTE: (1) Inspection or replacement cost estimates based on yearly costs amortized over a ten-year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14). Risk reduction factor is estimated for the component (if appropriate, also for indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section 3.
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.

95%

TABLE 4-6 (Continued)

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements Freq. Year	($K)(1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	System Failure	Effectiveness (6) Oil (5) Saved Barrels Oil	Cost Barrels ($K)	Comments
(D) RISER SHAFT Housing Bumper rail Product transfer pipe Bolts Brackets	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
	(b) Visual by diver	after leaks detected on water	NA	NA	NA	NI	NA	
	2 Dye tracing	6	-	NEG	NEG	IND	0	
	3(a) Hydrostatic(pressure drop)	after storm	NA	NA	NA	NI	NA	
	(b) Hydrostatic(pressure drop)	52	NA	NA	NA	NI	NA	
	4 Acoustic array	cont.	-	NEG	NEG	IND	0	
	5 Shroud with EMP pulsed coaxial cable	cont.	-	NEG	NEG	IND	0	
	6 Mfg. recommended inspection and maintenance		NA	NA	NA	NI	NA	
	7 Double walled pipe		-	NEG	NEG	IND	0	
	8 Diver NDT and visual (See recommended schedule Section 5.2 and Table 3-4)		-	0.2	NEG	IND	0	
(E) PLEM Piping Base hose Flanges Gaskets Chamber Check valves Ball valves Insulation valves Bolts Brackets	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
	(b) Visual by diver	after leak detected on water	NA	NA	NA	NI	NA	
	2(a) Optical borehole-PLEM chamber	2	-	0.9	NEG	IND	0	
	(b) Optical borehold - basehose	2	-	0.7	NEG	IND	0	
	3(a) Hydrostatic(pressure drop)	after storm	NA	NA	NA	NI	NA	
	(b) Hydrostatic(pressure drop)	52	NA	NA	NA	NI	NA	
	4 Acoustic array	cont.	50	0.5	NEG	0.5	0.1	
	5 Shroud with EMP pulsed	cont.	-	0.8	NEG	IND	0	
	6 Dye tracing	6	37	0.5	NEG	0.5	<0.1	Containment system over *PLEM*
	7 Mfg. recommended inspections and maintenance			NA	NA	NI	NA	
	8 Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-4)		-	0.3	NEG	IND	0	
(F) MOORING BASE External structure Bumper rail Siltation level Piles Anodes Scour protection Bolts Brackets	1 Visual by diver	after storm	NA	NA	NA	NI	NA	
	2 Scour	after storm	NA	NA	NA	NI	NA	
	3 Mapping	after storm	NA	NA	NA	NI	NA	
	4(a) Buoy position	after storm	NA	NA	NA	NI	NA	
	(b) Buoy position	12	-	0.5	NEG	IND	0	
	5 Mfg. recommended inspections and maintenance		NA	NA	NA	NI	0	
	6 Diver NDT and visaul- (see recommended schedule Section 5.2 and Table 3-4)		-	0.3	NEG	IND	0	

95%

(135)

Inspections are made primarily on components that, if broken, may cause ship breakout and result in hose rupture. These components include the center shaft extension, buoy universal joint, anchor chain attachment bracket, anchor chain, chain swivel, shaft universal joint, connector universal joint to the fluid swivel and bolts. Particularly effective NDT inspection techniques in addition to visual include magnetic foil or magnetic rubber, radioactive isotopes, active ultrasonics, seal leak detectors, tightness of bolts (torque), size measurements (particularly of chains or chain elements) and cathodic protection inspections.

Other particularly sensitive inspection methods would be to use dye tracing to inspect for leaks in the fluid seals and hose arm seals. A typical procedure would be to install a container over the swivel assembly or hose arm, insert a fluorocarbon dye under pressure into the OTS component and then pump the sampled water up a tube to a fluorometer detector in a boat.

Other less effective inspection methods include acoustic array, shroud with EMP pulsed coaxial cable and optical borehole inspection of the PLEM chamber or base hose. The reason that these methods are not too useful for SALM SPM applications is that oil spills from the OTS system components occur from very slow leaks primarily at the seals and these inspection methods are not very sensitive to those leaks or cannot be applied to those components.

Other inspection methods were already in use during the time period when the data were obtained and used for the determination of oil spill risks. Hence, these methods provide no improvement in risk reduction. These methods include visual by diver, buoy position location, manufacturer recommended inspections, hydrostatic (pressure drop), scour, and mapping of the buoy or mooring base location.

4.4.5.2 Estimation of Risk Reduction Achievable by Inspection of the SALM SPM

The primary source of oil spill risk, about 150 barrels a year, is the failure of the mooring system which causes ship breakout and results in hose rupture. An effective inspection of the mooring system components is their periodic visula and non-destructive examination. The risk reduction factor assessed for this is 0.1. Thus for periodic inspection using visual and NDT the reduced risk of barrels of oil spilled is:

(1-0.1) [150 (rupture prevention)] = 140 bbls/year.

The risk of spills from failure of other SALM SPM components is estimated at a total of 30 bbls/year. Spill risks from the fluid swivel assembly and hose are, each estimated at 15 bbls/year. Spill risks for the remaining components are estimated to be less than a barrel. Inspection of the fluid swivel seals by dye tracing is estimated to have a risk reduction factor of 0.5. Hence, the reduction in barrels spilled is:

(1-0.5) [15 (leak)] = 8 bbls/year.

4.4.6 CALM SPM

4.4.6.1 Preliminary Selection of Inspection Methods

Oil spill risks for the CALM SPM according to Section 3 of Reference 1 occur primarily from failure of the underbuoy hoses (786 barrels per year) and to a much lesser amount (about 55 barrels per year) from leaks, mainly from the seals of the product distribution unit. The risk data are based upon the same number of SPMs and operational conditions as assumed for the SALM described in Section 4.4.5.1. Inspection method selection was based upon information presented here and in previous sections (from the CALM configuration in Section 3-5, underwater hose string inspection method selection in Section 4.4.1 and from selection of SALM SPM

inspection methods in Section 4.4.5). Table 4-7 shows the selected inspection methods with inspection interval, estimated costs, risk reduction factors and effectiveness. Selected inspection methods for specific OTS components of the CALM SPM are noted in Table 3-5.

Inspection methods for the underbuoy hose string are essentially the same as the ones discussed in Section 4.4.1 and will not be repeated here.

The most effective inspection method for the CALM SPM are visual and NDT inspections (see Table 3-5 and Section 5.1) carried out on the internal structure of the mooring buoy. Particularly sensitive NDT inspection methods include active ultrasonics, X-ray, radioactive isotopes, magnetic particle, seal leak detection, tightness of bolts and cathodic protection inspection.

Other inspection methods and procedures for the OTS components of the CALM SPM are essentially the same as those described for the SALM SPM and will not be repeated here. These inspection methods, however, are given in Section 5.1 and Table 3-5.

4.4.6.2 Estimation of Risk Reduction Achievable by Inspection of the CALM SPM

According to Table 3-14 of Reference 1, the highest risk of oil spills for the CALM SPM stems from failures of the underbuoy hoses. Inspection techniques applicable to this component are the same as those for the floating hoses. Moreover, the risk reduction factors assessed for inspection of the floating hoses are assumed to be the same; these are listed in Table 4-7.

The risk of spills from the failure of the other components of the CALM is much less and arises primarily from leaks. From the Fault Tree D1 in Reference 1, the principle sources of leaks are the seals of the product distribution unit and damage inflicted by a ship collision. Lesser sources of leaks include the PLEM, valves and the

TABLE 4-7 COST-EFFECTIVENESS ANALYSIS FOR CALM SPM

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements: Freq. Year	($K) (1)	Risk Reduction Factor (2),(3),(4): Comp. Failure	Risk Reduction Factor (2),(3),(4): System Failure	Effectiveness (6): Oil (5) Saved Barrels Oil	Effectiveness (6): Cost Barrels ($K)	Comments
(A) MOORING BUOY								
External Structure	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
Navigation light	(b) Visual by diver	12	NA	NA	NA	NI	NA	
Fog Signal	2(a) Visual on buoy	after storm	NA	NA	NA	NI	NA	
Hull	(b) Visual on buoy	52	NA	NA	NA	NI	NA	
Fenders	3(a) Buoy position	after storm	NA	NA	NA	NI	NA	
Buoy Anodes	(b) Buoy position	1	NA	NA	NA	NI	NA	
Hoisting Equipment Winch	4 Mfg. recommended maintenance and inspections		NA	NA	NA	NI	NA	
	5 Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-5)		-	0.6	NEG	IND	0	
Internal Structure	1(a) Visual on buoy	after storm	NA	NA	NA	NI	NA	
Product distribution unit	(b) Visual on buoy	12	NA	NA	NA	NI	NA	
Flanges Seals	2 Mfg. recommended maintenance and inspections		NA	NA	NA	NI	NA	
Gaskets Piping Valves Rotating deck Brackets Power supply Fog signal Pumps Motors Bolts	3 Visual and NDT (see recommended schedule Section 5.2 and Table 3-5)		20	0.4	NEG	18	0.9	Includes seal leak detection and telltale
(B) UNDERBUOY HOSE STRING DURING OFFLOADING								
Hoses (Including Nipples, Flanges, Gaskets and Bolts	1(a) Visual by launch	once/ship	NA	NA	NA	NI	NA	
	(b) Visual by launch	once/2hrs	358	NEG	NEG	IND	< 0.1	
	(c) Visual by launch	cont.	700	0.9	NEG	25	< 0.1	
	2(a) Oil spill detector with launch	cont.	708	0.7	0.9	70	0.1	
	(b) Oil spill detector with launch	once/2hrs	358	NEG	NEG	IND	< 0.1	
	3 Visual on CALM	cont.	367	0.7	0.9	70	0.2	
	4(a) Buoy-type oil spill detec.	cont.	188	0.9	NEG	10	0.1	
	(b) Oil spill detec. on ship	cont.	77	0.9	NEG	10	0.1	
	5 OTS control system (pressure, flow) 1.0% accuracy	cont.	170	0.7	0.7	220	1.3	Sensors on ship CALM, PLEM, Platform
	6 OTS control system mathematical modeling 0.1% accuracy	cont.	190	0.7	0.7	220	1.1	Sensors on ship, CALM, PLEM, and pumping form
	7 Acoustic array	cont.	135	0.1	0.7	260	2	
	8 Shroud with EMP pulsed coaxial cable	cont.	123	0.3	0.7	200	1.6	
	9 Double walled hose	once/ship	-	NEG	NEG	0	0	
All Other Components	No methods							Inspect only when not offloading

NOTE: (1) Inspection or replacement cost estimates based on yearly costs amortized over a ten-year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14). Risk reduction factor is estimated for the component (if appropriate, also indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section 3.
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.

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TABLE 4-7 (Continued)

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements: Freq. Year	($K)[1]	Risk Reduction Factor (2),(3),(4): Comp. Failure	System Failure	Effectiveness(6) Oil(5) Saved: Barrels Oil	Cost: Barrels ($K)	Comments
(C) UNDERBUOY HOSE STRING NOT DURING OFFLOADING								
Hoses (Including Nipples, Flanges, Gaskets and Bolts	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
	(b) Visual by diver	after oil leak observed on water	NA	NA	NA	NI	NA	
	2 Optical borehole at hose flanges-hose evacuated	6	37	0.5	0.5	390	12	
	3 Dye tracing	52		0.1	0.1	700		Small leaks
	4(a) Hydrostatic(pressure drop)	after storm	NA	NA	NA	NI	NA	
	(b) Hydrostatic(pressure drop)	52		0.5	0.5	390		With leak detector
	5 Acoustic array	cont.	125	0.1	0.1	700	5.6	
	6 Shroud with EMP pulsed coaxial cable	cont.	125	0.3	0.3	550	4.2	
	7 Double walled hose	52	1600	0.1	0.1	700	0.4	
	8 Diver NDT and visual(see Section 5.2 for recommended schedule and Table 3-5)			0.5	0.5	390		
	9 Water left in hoses		45	0.01	NEG	20	0.5	
	10 Hose replacement	2 1 1/2		0.5 0.9 NA	0.9 NEG NA	 NA	 NA	
	11 2 and 8			0.3	0.3	550		
Other Components Flanges and bolts Flange seals Body floats Bouyancy tanks Brackets and bolts Gaskets and bolts Spreader bars	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
	(b) Visual by diver	after leak detected on water	NA	NA	NA	NI	NA	
	2 Diver NDT and visual see recommended schedule Section 5.1							
(D) PLEM								
Piping Flanges Gaskets Chamber Check valves Ball valves Isolation valves Bolts Brackets	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
	(b) Visual by diver	after oil leak detected on water	NA	NA	NA	NI	NA	
	2 Optical borehole PLEM chamber	2	-	NEG	NEG	IND	0	
	3(a) Hydrostatic(pressure drop)	after storm	NA	NA	NA	NI	NA	
	(b) Hydrostatic(pressure drop)	52	NA	NA	NA	NI	NA	
	4 Acoustic array	cont.	-	0.8	NEG	IND	0	
	5 Shroud with EMP pulsed coaxial cable	cont.	-	0.9	NEG	IND	0	
	6 Dye tracing	6	37	0.5	NEG	0.5	<0.1	Containment system on PLEM
	7 Mfg. recommended inspection and maintenance		NA	NA	NA	NI	NA	
	8 Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-5)		-	0.3	NEG	IND	0	

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TABLE 4-7 (Continued)

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements Freq. / Year	($K)(1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	System Failure	Effectiveness (6) Oil (5) Saved Barrels Oil	Cost Barrels / ($K)	Comments
(E) PLEM ANCHOR BASE								
Base assembly	1 Visual by diver	after storm	NA	NA	NA	NI	NA	
Piles	2 Scour	after storm	NA	NA	NA	NI	NA	
Brackets	3 Mapping	after storm	NA	NA	NA	NI	NA	
Bolts	4(a) Buoy position	after storm	NA	NA	NA	NI	NA	
Gaskets	(b) Buoy position	12	-	0.7	NEG	IND	0	
Flanges, Anodes, Scour	5 Mfg. recommended inspections and maintenance		NA	NA	NA	NI	NA	
	6 Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-5)		-	0.3	NEG	IND	NA	
(F) CHAIN ANCHOR	1(a) Visual by diver	after storm	NA	NA	NA	NI	NA	
	(b) Visual by diver	1	NA	NA	NA	NI	NA	
	2 Remove one chain and inspect	1	NA	NA	NA	NI	NA	
	3 Diver NDT and visual (see recommended schedule Section 5.2 and Table 3-5)		-	NEG	NEG	IND	0	Includes scour, continuity inspections, etc.

95%

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piping. An effective inspection of these components is periodic checks using visual and non-destructive methods. The risk reduction factor assessed for these is 0.4.

The estimation of the reduced volume of oil spilled was based on the following data (Table 3.14, Reference 1). The risk of rupture of the underbuoy hoses is 750 bbls/year and the risk of leaks from these hoses is 36 bbls/year. The risk of leaks from the other components is 30 bbls/year. Of the 750 bbls/year rupture risk, 250 bbls/year is associated with an assumed one-minute rupture detection time. Reliable and immediate detection of a rupture could reduce the spill risk that much. Thus, a control system with 1 percent accuracy has a 90 percent effectiveness (Table 4.7) for immediate leak detection and warning. Hence, the reduced barrels spilled is

$$(1-0.1)\,[250\ (\text{rupture detect})] = 220 \text{ bbls/year}.$$

The system risk reduction factor is

$$\frac{816-220}{816} = 0.7,$$

where 750 + 36 + 30 = bbls/year is the total system risk.

As another example, the passive acoustic array is effective as an incipient leak detector for the underbuoy hoses. Hence, the reduced barrels spilled is

$$(1-0.1)\,[36\ (\text{leaks}) + 750\ (\text{ruptures})] = 710 \text{ bbls/year}.$$

The risk reduction factor for the system is

$$\frac{816-710}{816} = 0.1.$$

For non-destructive testing of the PLEM, valves, piping and PDU, the reduced risk of spills is

$$(1-0.4)\,[30\ (\text{leaks})] = 18 \text{ bbls/year}.$$

The corresponding risk reduction factor for the system is

$$\frac{816-18}{816} = 0.98 \text{ bbls/year, which is negligible.}$$

4.4.7 Offshore Platform and the Pumping and Metering Systems

4.4.7.1 Preliminary Selection of Inspection Methods

Oil spill risks are quite low (a few barrels) as shown in Table 4-1 for the offshore platform and the pumping and metering systems. However, these low risks were determined in Section 3 of Reference 1 assuming that both a Spill Prevention Countermeasure and Control (SPCC) program were in effect and that a number of inspections were being carried out. These assumptions were used in the selection of the inspection methods. They are given in Table 4-8 with inspection intervals, estimated costs and risk reduction factors. Selected inspection methods are also noted in Table 3-6 for the specific OTS components. For most of these OTS components, inspection methods and procedures generally used at well maintained offshore platforms are adequate, and new or developmental inspection methods will not appreciably decrease the oil spill risk. This becomes apparent both in Table 4-8, where only a few new or developmental-type inspection methods are selected, and in the recommended inspection methods and inspection schedules given in Section 5.1. A discussion of areas where some of the selected inspection methods may reduce the risk or reduce the inspection costs are included in the following paragraphs.

Underwater inspections of the platform support are essential but costly because of the large area of platform structure that must be inspected. Lower inspection costs, wider area of coverage, and continuous inspection at critical areas of the structure are the potential advantages of an acoustic array. Improvements in risk reduction by the acoustic method would be small, at best, and probably would not be discernible. It appears feasible that a continuously monitoring acoustic array system (see Reference 47) can be used to detect and locate crack extensions due to fatigue and then to evaluate fatigue cracks growing on the offshore platform. In addition, it appears that corrosion products accumulated on crack surfaces also can be detected and located. Experimental acoustic systems are being used currently on a few platforms in Europe.

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TABLE 4-8 COST-EFFECTIVENESS ANALYSIS FOR OFFSHORE PLATFORM* AND THE PUMPING AND METERING SYSTEM

OTS COMPONENT		Inspection Method or Replacement	Inspections or Replacements Freq. Year	($K)(1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	System Failure	Effectiveness (6) Oil(5) Saved Barrels Oil	Cost Barrels ($K)	Comments
(A) PLATFORM SUPPORT									
	1	Visual	52	NA	NA	NA	NI	NA	
	2	Diver NDT	1	NA	NA	NA	NI	NA	
	3	Mapping	1	NA	NA	NA	NI	NA	
	4	Scour	1	NA	NA	NA	NI	NA	
	5	Acoustic array	cont.	-	0.5	0.5	IND	0	
	6	Strain or load measurements (strain gage, accel, etc.)	cont.	-	0.9	0.9	IND	0	
	7	Diver NDT (see recommended inspection schedule Section 5. and Table 3-6	1	-	0.7	0.7	IND	0	
(B) PLATFORM SUPPORT (Earthquake Structural Damage)									
	1	Visual	after earthquake	NA	NA	NA	NI	NA	
	2	Diver NDT	after earthquake	NA	NA	NA	NI	NA	
	3	Mapping	after earthquake	NA	NA	NA	NI	NA	
	4	Scour	after earthquake	NA	NA	NA	NI	NA	
	5	Acoustic array	cont.	-	0.5	NEG	IND	0	
	6	Strain or load measurements (strain gage, accel., etc.)	cont.	-	0.8	NEG	IND	0	
	7	Diver NDT (see recommended inspection schedule Section 5.2 and Table 3-6)		-	0.7	0.7	IND	0	
(C) SHIP NAVIGATIONAL AID Visual Radar Laser Sonar Microwave Fog horns Lights Misc.									
	1	Visual	365	NA	NA	NA	NI	NA	
	2	NDT	1	NA	NA	NA	NI	NA	
	3	Control room monitoring-alarms, shutoff, etc.	cont.	NA	NA	NA	NI	NA	
	4	Mfg. operational maintenance and inspections		NA	NA	NA	NI	NA	
	5	Recommended NDT (inspection schedule see Section 5.2 and Table 3-6)		NA	NA	NA	NI	NA	
(D) FIRE PROTECTION SYSTEM Gas detectors Fire detectors Oil spill detectors Sprinklers Firewater pump - Station Pumps Foam Fire extinguisher Misc.									
	1	Visual	365	NA	NA	NA	NI	NA	
	2	NDT	1	NA	NA	NA	NI	NA	
	3	Control room monitoring-alarms shutoff, etc.	cont.	NA	NA	NA	NI	NA	
	4	Mfg. operational maintenance and inspection		NA	NA	NA	NI	NA	
	5	Recommended NDT (inspection schedule see Section 5.2 and Table 3-6)		-	NEG	NEG	IND	0	

NOTE: (1) Inspection or replacement cost estimates based on yearly costs amortized over a ten-year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14. Risk reduction factor is estimated for the component (if appropriate, also indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section 3.
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.
* Cost-effectiveness analysis assumes that a Spill Prevention Counter Measure and Contol (SPCC) program is carried out; This includes, for example, curbing of platform to contain oil leakage.

95%

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TABLE 4-8 (Continued)

OTS COMPONENT		Inspection Method or Replacement	Inspections or Replacements Freq. Year	($K)(1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	System Failure	Effectiveness (6) Oil(5) Saved Barrels Oil	Cost Barrels ($K)	Comments
(E) WASTE DISPOSAL SYSTEM									
Hole in deck	1	Visual	365	NA	NA	NA	NI	NA	
Waste disposal system Tank	2	Oil spill detection on platform	cont.	2	0.5	NEG	IND	0	
Piping Valve	3	Oil spill detection buoy type	cont.	-	0.9	NEG	IND	0	
Sea sump	4	Dye tracing	1	NA	NA	NA	NI	0	
M.O. tank pump	5	Hydrostatic test	1	-	NEG	NEG	IND	0	
Air eliminator (Drain pipe valve open)	6	Acoustic array on tanks, piping, etc.	cont.	-	NEG	NEG	IND	0	
Reclaimed oil tank valve (closed)	7	Machinery vibration monitoring	cont.	-	0.9	NEG	IND	0	
Oil water sump Sea sump Bolts	8	Control room monitoring-alarms, shutoff, etc.	cont.	NA	NA	NA	NI	NA	
Flanges	9	NDT	1	NA	NA	NA	NI	NA	
	10	Mfg. recommended inspections, maintenance and operational checks		NA	NA	NA	NI	NA	
	11	Recommended NDT inspection schedule (see Section 5.2 and Table 3-6)	1	-	NEG	NEG	IND	0	
	12	Redundant equipment		NA	NA	NA	NI	NA	
	13	5 and 6	1	-	0.7	NEG	IND		
(F) UPSTREAM FROM PUMPS									
Upstream - Piping	1	Visual	365	NA	NA	NA	NI	NA	
Flange	2	Dye tracing	1	NA	NA	NA	NI	0	
Sampler - Drain valve	3	Hydrostatic tests	1	-	NEG	NEG	IND	0	
Left open Container	4	Acoustic array on piping, valves	cont.	-	0.8	NEG	IND	0	
Valve Strainer - Drain valve	5	Machinery vibration monitoring	cont.	-	0.9	NEG	IND	0	
Left open Basket	6	Machinery magnetic chip monitoring	cont.	-	0.9	NEG	IND	0	
Air Eliminator - Drain valve Left open	7	Control room monitoring - alarms shutoff, etc.	cont.	NA	NA	NA	NI	NA	
Chamber	8	NDT	1	NA	NA	NA	NI	NA	
High level Switch Bolts	9	Mfg. recommended inspection, maintenance and operation of checks		NA	NA	NA	NI	NA	
Flanges	10	Recommended NDT inspections (see Section 5.2 and Table 3-6)	1	-	0.8	NEG	IND	0	
	11	Redundant equipment		NA	NA	NA	NI	NA	
	12	4 and 5	1	-	0.7	NEG	IND	0	
(G) PUMP SECTION									
Piping	1	Visual	365	NA	NA	NA	NI	NA	
Pump-Valve	2	Dye tracing	1	-	NEG	NEG	IND	0	
MOV	3	Hydrostatic tests	1	-	NEG	NEG	IND	0	
Seals Bolts	4	Acoustic array on piping, valves, etc.	cont.	-	0.8	NEG	IND	0	
Flanges	5	Machinery vibration monitoring	cont.	-	0.8	NEG	IND	0	
	6	Machinery magnetic chip monitoring	cont.	-	0.8	NEG	IND	0	
	7	Control room monitoring alarms, shutoff, etc.	cont.	NA	NA	NA	NI	NA	
	8	NDT	1	NA	NA	NA	NI	NA	
	9	Mfg. recommended inspections, maintenance and operational checks		NA	NA	NA	NI	NA	
	10	Recommended NDT inspections (see Section 5.2 and Table 3-6)	1	-	0.8	NEG	IND	0	
	11	Redundant equipment		NA	NA	NA	NI	NA	
	12	3 and 4	1	-	0.8	NEG	IND	0	

95%

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TABLE 4-8 (Continued)

OTS COMPONENT		Inspection Method or Replacement	Inspections or Replacements Freq./Year	($K)(1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	System Failure	Effectiveness (6) Oil(5) Saved Barrels Oil	Cost Barrels/($K)	Comments
(H) DOWNSTREAM FROM PUMPS									
Meter Run - Valve	1	Visual	365	NA	NA	NA	NI	NA	
Control Velve	2	Dye tracing	1	NA	NA	NA	NI	NA	
Straightener	3	Hydrostatic testing	1	-	NEG	NEG	IND	0	
Turbine flow meter	4	Acoustic array on piping	cont.	-	0.8	NEG	IND	0	
Flange	5	Seal leak detection	1	-	0.9	NEG	IND	0	
Meter Prover - Valve **Diverter valve**	6	Control room monitoring alarms, shutoff, etc.	cont.	NA	NA	NA	NI	NA	
Drain	7	NDT		NA	NA	NA	NI	NA	
Line **Launcher - Vlave** **Container**	8	Mfg. recommended inspections, maintenance and operational checks		NA	NA	NA	NI	NA	
Drain valve (left open)	9	Redundant equipment		NA	NA	NA	NI	NA	
Gaskets **Flanges** **Bolts**	10	Recommended NDT inspections (see Section 5.2 and Table 3-6)		-	0.8	NEG	IND	0	
Piping **Brackets**	11	3 and 4	1	-	0.7	NEG	IND	0	

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Oil spill detectors located on the platform can be used to continuously monitor the water around and under the platform for spills from the waste disposal system. Less effective in situ buoy-type oil spill detectors can be installed in the water near potential spill areas of the platform.

Passive acoustic array can be especially effective in providing incipient failure detection if it is used during hydrostatic proof tests to detect and locate internal defects that can lead to leaks or rupture and which can not be detected by other NDT tests. This can be effective in reducing component risks when used for any of the tanks and piping on the platform.

Machinery monitoring for internal damage can be accomplished using vibration monitoring systems (acoustic, strain or acceleration) or magnetic chip monitoring. These methods can reduce maintenance and repair costs and can provide some component risk reduction but cannot provide system risk reductions that are discernible.

4.4.7.2 Estimation of Risk Reduction Achievable by Inspection of the Offshore Platform and the Pumping and Metering Systems

Oil spill risks for the offshore platform and the pumping and metering systems are almost negligible. Inspection methods and effectiveness values are included in Table 4-8 and will not be discussed further in this section. Recommended inspection methods, however, will be given in Section 5.1.

4.4.8 Onshore Pipeline and Appurtenances

4.4.8.1 Preliminary Selection of Inspection Methods

Another major source of potential deepwater port oil spillage is caused by onshore underground pipelines. The risk is about the same as for the undersea pipeline. This is apparent from the results given in Section 3 of Reference 1 and those shown in Table 4-1. It was assumed that three pipelines, 56 inches OD, about 21 miles long and buried about 3 feet, would be used. Other OTS pipeline components and

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appurtenances are given in Section 3.7. A number of inspection methods were selected for further evaluation for the following reasons: 1) high spill risk, 2) pipeline dimensions, 3) information presented in previous sections, and 4) the availability of many suitable inspection methods. Selected inspection methods are shown together with inspection intervals, estimated costs, risk reduction factors and effectiveness in Table 4-9. Selected inspection methods for specific OTS components of the onshore pipeline and appurtenances are identified in Table 3-7.

Onshore underground pipeline rupture is the major source of oil leakage in the pipeline primarily because of the large volume of oil that can be spilled. Inspections can be carried out that could reduce the frequency of rupture significantly. A major cause of underground pipeline rupture is external impacts such as excavating errors, or unauthorized or unsafe activities above or near the pipeline. An approach to reduce the frequency of rupture is to periodically survey the ground above the pipeline. This can be done either by air, using a helicopter, or on land, simply by a man walking along the line. Helicopter inspection costs would be minimal because these inspections could be carried out during daily flights of personnel or equipment from the onshore terminal to the pumping platforms. A continuously monitoring acoustic array could be used to detect and locate external impacts before rupture.

Another approach to rupture is either to detect the location of a leak before it grows to a critical size and causes a catastrophic failure, or to detect and locate the rupture quickly in order to shut the system down for containment and removal of the spilled oil. Continuously monitoring of a permanently installed acoustic array or a shroud with an EMP pulsed coaxial cable system could be used to detect and locate small leaks or ruptures. A highly accurate (0.1%) OTS control system that uses a mathematical monitoring approach and monitors various parameters of the input and output of the pipeline can be effective in indicating a rupture or detecting a large leak.

TABLE 4-9 COST-EFFECTIVENESS ANALYSIS FOR ONSHORE PIPELINE AND APPURTENANCES

OTS COMPONENTS	Inspection Method or Replacement	Inspections or Replacements: Freq. Year	Inspections or Replacements: ($K)(1)	Risk Reduction Factor (2),(3),(4): Comp. Failure	Risk Reduction Factor (2),(3),(4): System Failure	Effectiveness (6): Oil(5) Saved Barrels Oil	Effectiveness (6): Cost Barrels ($K)	Comments
(A) UNDERGROUND PIPELINE								
Pipe and Manifold Rupture	1(a) Visual	365		0.5	0.5	200		
	(b) Visual	26	NA	NA	NA	NI	NA	
	2 Inspection pig	2	250*	0.5	0.9	300	1.2	
	3 Hydrostatic (Pressure drop)	1	6	0.5	NEG	300	50	Assume leak detection
	4 Dye insertion-for location	when leak detected	NA	NA	NA	NI	NA	
	5 Pressure crack wave	1	-	0.6	NEG	IND	0	
	6 Passive ultrasonic - for location	when leak detected	NA	NA	NA	NI	NA	
	7 OTS control system (pressure, flow, volume) 1% accuracy	cont.	NA	NA	NA	NI	NA	
	8 OTS control system - mathematical modeling 0.1% accuracy	cont.	20	0.5	0.5	500	25	
	9 Acoustic array	cont.	170	0.1	0.1	920	5	
	10 Shroud with EMP pulsed coaxial cable	cont.	100	0.3	0.6	420	4	
	11 3 and 9	1	176	0.1	0.5	560	3.2	
	12 Internal NDT	2	100	0.3	0.6	420	4.2	
	13 Corrosion-flow sampling	26	20	0.9	0.9	60	3	
	14 Inspection pig-3d	2	300	0.1	0.5	560	2	Ultrasonic imaging
Corrosion	1 Inspection pig	2	250*	0.1	NEG	14	< 0.1	
	2 Hydrostatic	1	6	0.5	NEG	8	1.3	
	3 Corrosion-flow sampling program	26	20	0.5	NEG	8	0.3	
	4 Acoustic array	cont.	170	0.1	NEG	14	< 0.1	
	5 Internal NDT	1	50	0.1	NEG	14	0.3	May be unsafe
	6 2 and 4	1	176	0.1	NEG	14	0.1	
Welds	1 Inspection pig	2	250*	0.1	NEG	14	< 0.1	
	2 Hydrostatic	1	6	0.5	NEG	8	1.2	
	3 Acoustic array	cont.	170	0.1	NEG	14	< 0.1	
	4 Internal NDT	1	50	0.1	NEG	14	0.3	
	5 NDT (Sampling external)	1	50	0.5	NEG	8	0.3	
Cathodic Protection	1 Mfg. recommended inspection schedule and maintenance	-	NA	NA	NA	NI	NA	
(B) OTHER COMPONENTS								
Seals Gaskets Flanges Valves	1 OTS control system mathematical modeling 0.1% accuracy	cont.	-	0.9	NEG	IND	0	
	2 Hydrostatic	1	-	0.5	NEG	IND	0	
	3 Acoustic array	cont.	-	0.1	NEG	IND	0	
	4 Internal NDT	1	-	0.05	NEG	IND	0	
	5 NDT (external sampling)	1	-	0.1	NEG	IND	0	
	6 2 and 3	1	-	0.4	NEG	IND	0	
	7 Mfg. recommended inspection and maintenance		NA	NA	NA	NI	NA	

NOTE: (1) Inspection or replacement cost estimates based on yearly costs amortized over a ten year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14. Risk reduction factor is estimated for the component (if appropriate, also indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section 3.
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.

* Costs are uncertain because no inspection pigs are currently available for 54-inch diameter pipeline. Higher cost than for smaller diameter pipelines are expected in order to help defray cost of building an inspection pig for limited usage.

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TABLE 4-9 (Continued)

OTS COMPONENT		Inspection Method or Replacement	Inspections or Replacements Freq./Year	($K) (1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	System Failure	Effectiveness (6) Oil (5) Saved Barrels Oil	Cost Barrels ($K)	Comments
(C) ABOVE GROUND PIPELINE (All Components)			26	NA	NA	NA	NI	NA	
	1	Visual	52	-	0.7	NEG	IND	0	
	2	Hydrostatic (Pressure drop)	1	-	0.5	NEG	IND	0	
	3	External hydrostatic	1	-	0.7	NEG	IND	0	
	4	Acoustic array	cont.	-	0.1	NEG	IND	0	
	5	NDT (see recommended schedule Section 5.2 and Table 3-7)	1	-	0.1	NEG	IND	0	
	6	2 and 4	1	-	0.2	NEG	IND	0	
(D) BOOSTER STATION (All Components)	1	Visual	52	NA	NA	NA	NI	NA	
	2	Hydrostatic	1	-	0.5	NEG	IND	0	
	3	Mfg. inspection schedule	1	NA	NA	NA	NI	NA	
	4	Control system monitors, alarms	cont.	NA	NA	NA	NI	NA	
	5	Acoustic array	cont.	-	0.5	NEG	IND	0	
	6	Vibration monitoring	cont.	-	0.5	NEG	IND	0	
	7	2 and 5	1	-	0.3	NEG	IND	0	
	8	NDT (see recommended schedule Section 5.2 and Table 3-7)	1	-	0.2	NEG	IND	0	

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A conventional and accurate (1%) OTS control system that continuously monitors flow, pressure and volume at the input and output of the pipeline would be less sensitive but would detect a rupture. Neither type of OTS control system could provide the location of rupture, so leak location methods would be required. Inspection pigs (see also Section 4.4.4.1) can be effective in detecting and locating small leaks or defective areas that can lead to rupture. Cost considerations generally prevent inspections that are frequent enough to provide optimum incipient failure detection. Manned inspection pigs using NDT techniques can also be used to inspect all or a sampling of the inside of the pipeline. Cost considerations again generally prevent inspections that are frequent enough to be very effective in providing incipient failure detection of most of the causes of pipeline rupture. Other potential but less effective techniques include the following: a passive ultrasonic sensor inserted through the ground onto the pipeline to locate the sounds emitted from a rupture or a large leak; dye insertion into the pipeline, particularly useful when a previous leak may have already contaminated the earth around a leak area; hydrostatic tests; crack-reflected pressure wave. A double-walled pipe would essentially eliminate rupture and could provide for easy detection of leaks, but costs are too high for the method to be given serious consideration.

Yearly hydrostatic testing when used with acoustic array provides a much greater improvement in incipient failure detection than just using hydrostatic testing by itself. This is discussed for the undersea pipeline in Section 4.4.4.1 and applies in a like manner for the underground pipeline.

Corrosion and defective welds are identified in Reference 1 and Table 4-1 as the cause of a high frequency of low volume oil spill incidents for underground pipelines. Risks are about the same as for the undersea pipeline discussed in Section 4.4.4. Inspection methods which appear to have potential for risk reduction include a number that have been previously discussed for the undersea pipeline.

These include: inspection pigs, hydrostatic pressure drop, a corrosion flow sampling program and acoustic array. A manned internal inspection of the pipeline appears practical for underground pipelines. An approach would be to inspect visually and with NDT sample sections of the pipeline. Methods ranging from a powered inspection vehicle with inspectors and equipment to an inspector on a dolly could be used. Highly reliable inspection equipment such as active ultrasonics, back scatter gamma ray, ultrasonic imaging, etc., could be used. Access ports would be required at suitable locations along the pipeline.

Cathodic protection inspections should be carried out using manufacturer-recommended inspection schedules. Methods typically used would include measurement of electric potentials, electric continuity, amount of wastage and visual examination of external damage or corrosion.

Above ground pipeline and appurtenances can be inspected easily with good sensitivity, high reliability and low cost using inspection methods and schedules used at well maintained onshore pipeline facilities. Above ground inspections provide the opportunity to use almost any non-destructive inspection method. Use of visual, state-of-the-art and new inspection methods such as ultrasonic imaging, seal leak detector, magnetic rubber and external hydrostatic should further reduce the risk of failure of the pipeline. Hydrostatic tests of above ground pipelines could be carried out without the problem of what to do if a leak occurs because above ground pipelines can be repaired quickly and easily. Passive acoustic array can be especially effective in providing incipient failure detection; this occurs when it is used during hydrostatic proof tests to detect and locate internal defects before leaks or potential failures can occur.

The booster station selected inspection methods are about the same as for the above ground pipeline except for the addition

of continuous control system monitoring of critical booster station components, vibration and magnetic chip monitoring.

4.4.8.2 Estimation of Risk Reduction Achievable by Inspection of Onshore Pipeline and Appurtenances

As for the undersea pipeline, ruptures of the pipeline can occur both from damage caused by "third party" activities (e.g., excavation and construction) and from general deterioration. Of the inspection methods listed in Table 4.7, daily visual surveys of the pipeline would be primarily effective against "third party" damage. For this a risk reduction factor of 0.5 was assessed.

A control system supplemented by mathematical analysis of the flow would be a defense to limit the amount of oil lost following a rupture; as for the undersea pipeline, a risk reduction factor of 0.5 was assessed for this method.

Use of a passive acoustic array could provide for incipient detection of failures leading to ruptures, immediate indication of external damage and the location of the rupture. For this method a risk reduction factor of 0.1 was assessed. The EMP pulsed coaxial cable was judged to be somewhat less effective for the detection of incipient failures; a risk reduction factor of 0.3 was assessed.

Yearly hydrostatic testing of the pipeline was judged to be capable of detecting incipient failures fairly effectively. However, if used with an acoustic array, a much greater effectiveness probably can be achieved since the pipeline's response to changes in stress levels can be monitored. The risk reduction factors assessed for these two methods were 0.5 and 0.1, respectively.

The detection of leaks and incipient failures caused specifically by corrosion and defective welds can be accomplished by any of several effective methods. Inspection pigs, internal non-destructive testing, acoustic array and hydrostatic testing in conjunction with

an acoustic array were estimated to have risk reduction factors of 0.1. Hydrostatic testing alone and sampling of the flow for corrosion products were estimated to be less effective.

The estimation of the reduced volumes of oil spilled achieved because of inspection was based on the data listed in Table 3.14 of Reference 1. The spill risk from ruptures is 1000 bbls/year, and from leaks it is 32 bbls/year. As for the undersea pipelines, it was assumed that the rupture risk arises in part from "third party" damage, 400 bbls/year, and in part from deterioration, 600 bbls/year. Examples of the calculations of the reduced volumes of oil spilled are presented in Section 4.4.4.2.

Oil spill risks for the above ground pipeline and booster station are almost negligible. Inspection methods and effectiveness values are included in the Table 4-4 and will not be discussed further in this section. Recommended inspection methods and procedures, however, will be given in Section 5.1.

4.4.9 Onshore Storage Terminal

4.4.9.1 Preliminary Selection of Inspection Methods

Oil spill risks are negligible (about 0.1 barrels per year) for onshore storage facilities as shown in Table 4-1. These low risks exist only because the onshore storage terminal is assumed to have a secondary containment system, which is typically a retaining dike around the onshore terminal limiting the possibility of oil leakage outside the facility. Hence, the only important inspection methods for the onshore storage terminal are the ones that are used to inspect the secondary containment system. Inspection methods were selected for OTS components shown in Section 3.8 and assuming 56-inch OD pipelines with about 10 miles underground and about 1/2 mile of above ground piping. Table 4-10 shows the selected inspection methods together with inspection intervals, estimated costs, risk reduction factors and effectiveness. Selected inspection methods

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for specific onshore storage terminal OTS components are noted in Table 3-8.

4.4.9.2 Estimation of Risk Reduction Achievable by Inspection of the Onshore Storage Terminal

Oil spill risks for the onshore storage terminal are negligible. Inspection methods and effectiveness values are included in Table 4-10 and will not be discussed further in this section. Recommended inspection methods, however, will be given in Section 5.1.

TABLE 4-10 COST-EFFECTIVENESS ANALYSIS FOR ONSHORE STORAGE TERMINAL*

OTS COMPONENT	Inspection Method or Replacement	Inspections or Replacements Freq. Year	($K)(1)	Risk Reduction Factor (2),(3),(4) Comp. Failure	System Failure	Effectiveness (6) Oil(5) Saved Barrels Oil	Cost Barrels ($K)	Comments
SECONDARY CONTAINMENT SYSTEM								
(A) DRAINAGE CONTROL SYSTEM								
Retaining dikes	1 Visual	365	NA	NA	NEG	NI	NA	
Gate valve								
	1 Visual	365	NA	NA	NA	NI	NA	
	2 Control monitor	cont.	NA	NA	NA	NI	NA	
	3 NDT inspection schedule (see Section 5.2 and Table 3-8)		-	NEG	NEG	IND	0	
(B) OTHER ONSHORE FACILITY COMPONENTS								
Pipe and manifold Above ground								
Corrosion	1 Visual	365	NA	NA	NA		NA	
Defective weld	2 Hydrostatic (pressure drop)	1	-	0.5	NEG	IND	0	
Rupture, damage, other failure	3 External hydrostatic	1	-	0.2	NEG	IND	0	
	4 Acoustic array		-	0.1	NEG	IND	0	
Cathodic protection	5 2 and 4		-	0.2	NEG	IND	0	
Seals, Gaskets, Flanges	6 Mfg. recommended inspections and maintenance		NA	NA	NA	NA	NA	
Valves	7 NDT (see recommended schedule Section 5.2 and Table 3-8)		-	0.8	NEG	IND	0	
Pipe and Manifold Below Ground								
Pipe and manifold Rupture	1(a) Visual	365	-	0.5	NEG	IND	0	
	(b) Visual	26	NA	NA	NA	NI	NA	
	2 Inspection pig	2	-	0.1	0.9	IND	0	
	3 Hydrostatic (pressure drop)	1	-	0.5	NEG	IND	0	
	4 Dye insertion for location	when leak detected	-	NEG	NEG	IND	0	
	5 Pressure crack wave	1	-	0.6	NEG	IND	0	
	6 Passive ultrasonic (for location)	when leak detected	-	0.9	NEG	IND	0	
	7 OTS control system (pressure, flow, volume) 1.0% accuracy	cont.	NA	NA	NA	NI	NA	
	8 OTS control system mathematical modeling 0.1% accuracy	cont.	-	0.5	0.5	IND	0	
	9 Acoustic array	cont.	-	0.1	0.1	IND	0	
	10 Shroud with EMP coaxial cable	cont.	-	0.2	0.2	IND	0	
	11 3 and 9	1	-	0.3	NEG	IND	0	
	12 Internal NDT (inspectors inside pipe)	1	-	0.1	NEG	IND	0	May be unsafe
	13 NDT-external (sample inspections)	1	-	0.5	NEG	IND	0	
	14 See recommended NDT inspection schedule Section 5.2 and Table 3-8		-	0.9	NEG	IND	0	
	15 Mfg. recommended inspections and maintenance		NA	NA	NA	NI	NA	
Corrosion	1 Inspection pig	2	-	0.1	NEG	IND	0	
	2 Hydrostatic (pressure drop)	1	-	0.5	NEG	IND	0	
	3 Corrosion flow sampling program	26	-	0.5	NEG	IND	0	
	4 Acoustic array	cont.	-	0.1	NEG	IND	0	
	5 Internal NDT	1	-	0.1	NEG	IND	0	

NOTE: (1) Inspection or replacement cost estimates based on yearly costs amortized over a ten year period.
(2) Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with no inspection (Reference 1, Table 3-14). Risk reduction factor is estimated for the component (if appropriate, also indicated failure mode) and for the OTS system that includes the component.
(3) NI-No improvement in risk reduction because method was commonly used when risks were determined in Reference 1, Section
(4) NEG-Negligible value for risk reduction factor (>0.95).
(5) IND-Improvement not discernible.
(6) NA-Not applicable since method was commonly used when risks were determined in Reference 1, Section 3.
* Cost-effectiveness analysis assumes that a Spill Prevention Counter Measure and Control (SPCC) program is carried out.

TABLE 4-10 (Continued)

OTS COMPONENT		Inspection Method or Replacement	Inspections or Replacements: Freq. Year	($K)(1)	Risk Reduction Factor (2),(3),(4): Comp. Failure	System Failure	Effectiveness (6): Oil (5) Saved Barrels Oil	Cost Barrels ($K)	Comments
Corrosion (Cont'd)	6	2 and 4	1	-	0.1	NEG	IND	0	
	7	Mfg. recommended inspections and maintenance		NA	NA	NA	NI	NA	
	8	NDT-external (sample inspections)	1	-	0.5	NEG	IND	0	
	9	See recommended NDT inspection schedule Section 5.2 and Table 3-8		-	0.9	NEG	IND	0	
Welds	1	Inspection pig	1	-	0.1	NEG	IND	0	
	2	Hydrostatic	1	-	0.5	NEG	IND	0	
	3	Acoustic array	cont.	-	0.1	NEG	IND	0	
	4	Internal NDT	1	-	0.1	NEG	IND	0	May be unsafe
	5	NDT-external (sample inspections)	1	-	0.9	NEG	IND	0	
Other Components Seals Gaskets Flanges Valves	1	OTS control system mathematical modeling 0.1% accuracy	cont.	-	0.9	NEG	IND	0	
	2	Hydrostatic	1	-	0.5	NEG	IND	0	
	3	Acoustic array	cont.	-	0.1	NEG	IND	0	
	4	Internal NDT	1	-	0.1	NEG	IND	0	
	5	NDT external (sample inspection)		-	0.5	NEG	IND	0	
	6	2 and 3		-	0.3	NEG	IND	0	
	7	Mfg. recommended inspections and maintenance		NA	NA	NA	NI	NA	
	8	See recommended NDT schedule Section 5.2 and Table 3-8		-	0.9	NEG	IND	0	
(C) MISCELLANEOUS COMPONENTS									
Strainer-Drain valve	1	Visual	365	NA	NA	NA	NI	NA	
Container	2	Dye tracing	1	NA	NA	NA	NI	NA	
Valve	3	Hydrostatic	1	-	NEG	NEG	IND	0	
Pig Receiving Trap-	4	Acoustic array	cont.	-	0.9	NEG	IND	0	
Container	5	Seal leak detector		-	0.9	NEG	IND	0	
Valve Gaskets	6	Control room monitoring alarms, shutoff, etc.		NA	NA	NA	NI	NA	
Door	7	NDT	1	NA	NA	NA	NI	NA	
Custodial Metering Runs (see Table 4-8)	8	Mfg. recommended inspections, maintenance and operational checks		NA	NA	NA	NI	NA	
	9	Recommended NDT inspections (see Section 5.2 and Table 3-8)			NEG	NEG	IND	0	
	10	Redundant equipment		NA	NA	NA	NI	NA	

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5.0 RECOMMENDED INSPECTION METHODS AND PROCEDURES

5.1 DISCUSSION

The objective of this study was to develop inspection methods and procedures to insure the integrity of the oil transfer system and to minimize the number and extent of pollution incidents at deepwater ports. The results of the System Safety Analysis Report in Reference 1 were used to identify those OTS components that cause high oil spill risks and are most prone to failure. The best equipment and technology in current use were utilized with consideration given to their capability to provide incipient failure detection, identification of the defective components, positive results, easily understood procedures and operations, minimal costs and adaptability to conventional OTS facilities. This effort was carried out in Sections 2 and 3. In addition, new, untested, or developmental methods were also considered. This was done when potential failure modes could not be adequately inspected by existing methods or when the possibility existed of substantially reducing either pollution incidents or inspection costs. Over fifty-six inspection methods in nine areas were found to be potentially applicable to typical DWPs. A cost-effectiveness analysis was carried out in Section 4 for the inspection methods and procedures that were considered to provide the best available technology for a hypothetical deepwater port in U.S. waters. All significant costs were used in the evaluation. Effectiveness was measured by considering both the probability of a pollution incident caused by an OTS component failure and the probability of detecting incipient failure. Again, all significant factors such as inspection method, reliability, operational readiness and design adequacy were considered.

The cost-effectiveness analysis was the primary consideration for recommendations of the inspection methods and procedures to be described subsequently. This was also used in the recommendations of alternate or backup methods that might be needed because of circumstances caused, for example, by operational or

environmental conditions. Consideration also was given to the use of more than one inspection method in situations where a single method did not provide an adequate, effective inspection, such as for the inspection of hose strings. In order to minimize cost effectively, the use of both sequential inspection methods, that provide increasing level of detail and the use of an inspection method in multiple applications to help defray costs, were also evaluated.

Recommended inspection methods and procedures include many inspections which are normally practiced at well-maintained facilities and are effective. These inspections may not necessarily produce a reduction in the risk primarily because their use has already effected a low oil spill risk. Examples of this are the use of the well-developed techniques for inspections of offshore platform supports, navigation equipment, piping, machinery, etc. However, for many OTS components such as hose strings, pipelines and mooring systems, new or developmental inspection methods and procedures are available which can substantially reduce oil spill risks (see Sections 4.4.1, 4.4.2, 4.4.4, 4.4.5, 4.4.6 and 4.4.8); only a few of the methods have been implemented and at only a few facilities. There has been very little initiative on the part of owners or operators to develop or adapt these advanced periodic or continuous inspection methods to their facilities. While the initial costs of these methods are usually higher than conventional methods, such as visual inspection, the life-cycle costs in many cases are lower. For example, the load monitor and acoustic array system may effectively substitute for inspectors on the deck of the ship or launch, launches, diving operations, etc., and consequently eliminate or significantly reduce the costs. From cost considerations, alone, some of these methods should be attractive.

Minimizing the number and extent of pollution incidents requires implementation of inspection methods and procedures that may necessitate some added costs.* For example, using a mooring line load monitor which only sounds an alarm when excess loading occurs is a good low cost approach to reducing risks. However, continuously monitoring the loads, possibly with a low-cost computerized system, and the

* These costs are very low considering the cost of facility and normal operational costs.

scheduling of mooring load system calibrations would provide more effective incipient failure detection and thereby help in minimizing the number and extent of pollution.

Another example is the use of a single inspector on the deck of the ship during offloading. The inspector watches for leaks in the hoses, ship connections, ship breakout, etc. This is a good step for maintaining the oil spill risks given in Reference 1, but not for minimizing the risks. A single inspector cannot see all pertinent events occuring. The inspector can provide little or no incipient failure detection. For example, he has difficulty in inspecting the hose string for small leaks, particularly in darkness and in bad weather. In many cases, if these leads are not detected early, a major oil spill could occur. Use of simultaneous inspection methods and procedures would help to minimize these types of oil spill risks and is recommended. The use of inspectors continuously patrolling in a small boat, for example, to aid in continuously monitoring the hose string and mooring lines, could significantly reduce oil spill risks. This is being done at some DWP facilities. Additional inspectors on the deck of the ship could further minimize the risk of oil pollution incidents. Developmental methods such as double walled hose for a complete hose string or a passive acoustic array system become available, fewer inspectors would be required while the risk of oil spill incidents would be reduced significantly.

Recommended inspection methods and procedures, and replacement of OTS components are given in Section 5.2. Recommended schedule of inspection and replacement intervals are also included.

Inspection methods recommended for development are discussed in Section 5.3.

5.2 RECOMMENDED INSPECTION METHODS AND PROCEDURES FOR THE DEEPWATER PORT OIL TRANSFER SYSTEM

Recommended inspection methods to minimize oil spill risks at deepwater ports are given in this section. Inspection methods and procedures, using the best equipment and technology in current use, are included for the major OTS components in the following seven subsections. These recommendations are intended to be general in nature and may be varied somewhat depending upon a number of considerations such as the specific design of the OTS components, DWP usage, etc. For simplicity and ease of understanding, however, inspections and recommendations are given in detail for some of the OTS components that have high oil spill risks or where general recommendations may not be adequate. Recommended inspection methods that require further development or testing can either further minimize the oil spill risk or can substantially improve the cost-effectiveness if substituted for recommended inspections that are in current use. These methods will not be discussed in this section but will be addressed in Section 5.3.

It should be noted that recommended inspection methods and procedures and replacements may result in some duplication of inspections. Hence the actual effectiveness (reduction of barrels of oil spilled) of a particular method may not be as high as indicated in Tables 4-2 through 4-10. However, if this occurs, the system effectiveness of a particular inspection is improved. Also, the cost of a particular method may typically be lower than indicated in these tables because the inspection method may be used for multiple inspection. For example, visual inspections from a launch can be used for inspecting the hose string, mooring system and SPM.

5.2.1 <u>Hose String, Shipboard Connections and Mooring System</u>

Recommended inspections and replacements for the hose string, shipboard connections and mooring system include the following:

(1) Hose String

- Periodic visual inspections from launch (see Section 5.2.1.1) with
  - oil spill detection
  - ultraviolet light
- Continuous visual inspections from deck of ship (see Section 5.2.1.2) with
  - low-light TV
  - ultraviolet light
- Continuous visual inspection from launch (see Section 5.2.1.3) with
  - oil spill detector
  - ultraviolet light
- Hydrostatic tests (see Section 5.2.1.5)
- Dye tracing (see Section 5.2.1.6)
- Diver NDT and visual (see Section 5.2.1.7)
- Hose replacement (see Section 5.2.1.8)
- Hose replacement (see Section 5.2.1.9)

(2) Mooring System

- Periodic visual inspection from launch (see Section 5.2.1.1)
- Continuous visual inspection from deck of ship (see Section 5.2.1.2) with
  - low-light TV
- Continuous visual inspection from launch (see Section 5.2.1.3)
- Mooring load monitor system (see System 5.2.1.4)
- Diver NDT and visual (see Section 5.2.1.7)
- Hawser replacement (see Section 5.2.1.0)

(3) Shipboard connections

- Continuous visual inspections on deck of ship (see Section 5.2.1.2)

A recommended schedule of these inspections and replacements is given in Table 5-1. Inspection methods and procedures and replacements are described in detail in subsections that follow.

Inspection methods and procedures recommended for the hose string and mooring system, if implemented should be very effective in minimizing the oil spill risk. It is estimated that the relative barrels of oil spilled will be reduced from about 3200 to about 800 barrels per year. Except for the mooring load monitoring, however, recommended inspection methods (periodic and continuous inspections from launch) that are highly effective (see Tables 4-2 and 4-3) in reducing the barrels of oil spilled, are not very cost-effective (relative value of approximately 1). Additionally, all methods recommended, except mooring load monitoring, are not very effective in darkness or in bad weather.

Inspection methods that aid visual inspection such as an oil spill detector on the launch, low-light TV and ultraviolet light are all highly cost-effective and should be implemented in a DWP inspection program. Periodic inspection methods such as dye tracing, and hydrostatic tests, diver NDT and visual, provide good incipient failure detection and have relatively high cost-effectiveness values.

Recommended replacement intervals of the hose string and hawser are necessary. Replacements are extremely expensive and result in very poor cost-effectiveness values (<<1 bbl /K$). However, extending the replacement schedule may increase the relative oil spill risk to a higher value than indicated in Table 4-1 and is not recommended.

TABLE 5-1 RECOMMENDED SCHEDULE FOR INSPECTIONS AND REPLACEMENTS OF OTS COMPONENTS FOR HOSE STRING, SHIPBOARD CONNECTIONS AND MOORING SYSTEM

OTS COMPONENT	SHIP IN BERTH				PERIODICITY (1)															
	Before	During Off Loading		After	Cont.	Hours		Days	Weeks		Months				Years			Once	After	
		Yes	No			2	8	1	1	2	1	2	3	6	1	3	5	Per Ship	Storm	Collision
HOSE STRING	X																	5.2.1.1	5.2.1.1	5.2.1.1
			X		5.2.1.2															
		X			5.2.1.2															
		X			5.2.1.3															
		X			5.2.1.4															
			X					5.2.1.1												
				X					5.2.1.5	5.2.1.6										
				X					5.2.1.7		5.2.1.7	5.2.1.7		5.2.1.7					5.2.1.7	5.2.1.7
				X										5.2.1.8	5.2.1.9					
	X	X	X	X	5.3.1.1															
		X			5.3.1.2															
		X			5.3.1.3															
		X			5.3.1.4															
				X								5.3.1.5								

(1) For recommended inspection or replacement event, see the Section identified.

TABLE 5-1 RECOMMENDED SCHEDULE FOR INSPECTIONS AND REPLACEMENTS OF OTS COMPONENTS FOR HOSE STRING, SHIPBOARD CONNECTIONS AND MOORING SYSTEM (Continued)

OTS COMPONENT	SHIP IN BERTH				PERIODICITY															
	Before	During Off Loading		After	Cont.	Hours		Days	Weeks		Months				Years			Once Per Ship	After	
		Yes	No			2	8	1	1	2	1	2	3	6	1	3	5		Storm	Collision
SHIPBOARD CONNECTIONS																				
		X			5.2.1.2															
MOORING SYSTEM			X					5.2.1.1												
			X		5.2.1.2															
		X			5.2.1.3															
		X			5.2.1.4															
				X				5.2.1.7			5.2.1.7	5.2.1.7		5.2.1.7					5.2.1.7	5.2.1.7
				X										5.2.1.10						

(66)

5.2.1.1 Periodic Visual Inspections from Launch

OTS Component
Hose string, mooring system

Periodicity
Before ship berths

Inspection Method
Visual from launch with one crewman and one inspector

Special Equipment
Lighting, oil spill detector with alarm which discriminates between thin oil film and thick oil film, ultraviolet light

Safety Precautions
No special precautions

Inspections

(1) Hose string

Floating hose string

a. Leakage
b. External damage including:

- kinking
- cracks
- stretching
- nipple corrosion
- buoyancy tanks in proper position
- bulges
- wires showing
- creases
- cuts
- abrasion
- wear
- rubber disintegration
- collapse
- safety blinker lights operating
- indentations
- crushing
- loss of buoyancy
- loss of floats
- marine growth

c. Correct configuration
d. Fouling with each other
e. Stream out and floating freely
f. Damage to floatation medium
g. Flanged joints and hoses examined for leakage stains
h. Odor from oil leakage
i. Debris
j. Looseness or loss of assemblies

5.2.1.1 (Continued)

<u>Submarine hose string</u>

a. Leakage
b. Inclination of first underwater hose section
c. Loss of assemblies

<u>Pickup buoys and support wire floats</u>

a. Physical damage
b. Apparent loss of buoyancy
c. Free floating in water

<u>Inspection devices on hose string</u>

a. Proper operation
b. Proper configuration
c. External damage
d. Security of fasteners

(2) Mooring system

<u>Mooring hawsers</u>

a. Free streaming
b. No snarls with flotation hoses or debris
c. External damage

<u>Buoy chafing chain</u>

a. Chafing
b. Wear
c. Corrosion
d. External damage

<u>Chain support buoy and connection</u>

a. Physical damage to attachment hardware
b. Chafing chain friction to polyurethane shell
c. External damage
d. Apparent loss of buoyancy
e. Free floating in water

<u>Inspection equipment for mooring system</u>

a. Proper operation
b. Proper configuration
c. External damage
d. Security of fasteners

5.2.1.2 Continuous Visual Inspection from Deck of Ship

OTS Components
Hose string, shipboard connections, mooring system

Periodicity
Continuous during offloading

Inspection Method
Visual from deck of ship using 2 inspectors

Special Equipment
Low-light TV monitor, ultraviolet light

Safety Precautions
No special precautions

Inspections

1. Hose string

Floating hose string

a. Leakage
b. Correct configuration
c. Fouling with each other
d. Stream out and flowing freely
e. Damage to floatation medium
f. External damage

- kinking
- bulges
- wires showing
- rubber desintegration
- wear rate of chains and fittings
- bouyancy tanks in proper position
- collapse
- crushing
- loss of bouyancy
- marine growth
- safety blinker lights operating

g. Loss of assemblies
h. Debris
i. Rail hose defects

- leakage while pressurized
- kinks
- chafing
- physical damage
- includes all inspections of item f, above

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5.2.1.2 (Continued)

Submarine hose string

a. Leakage
b. *Inclination of first underwater hose section*
c. Loss of assemblies

Inspection equipment for hose string

a. Proper operation
b. Security of fasteners

(2) Shipboard connections

Connections

a. Ship manifold expansion joint defects
   - leakage
   - damage
     - cracks
     - impacts
   - security of fastenings
   - corrosion

b. Ship manifold defects
   - leakage
   - damage
     - cracks
     - impacts
   - weld defects
   - security of fastenings
   - corrosion

c. Gasket (between hose flange and manifold) defects
   - leakage
   - external damage
   - security of fasteners
   - corrosion

d. Ship manifold valve defects
   - leakage
   - valve operational characteristics
   - external damage
     - cracks
     - pitting
   - corrosion

5.2.1.2 (Continued)

e. Drip tank defects
   - Liquid level
   - leakage
   - external damage
     - -cracks
     - -pitting
     - -miscellaneous
   - corrosion
   - overfilled

f. Scuppers plugged

Shipboard operations

a. Proper operating pressures
b. Proper discharge operations
c. Proper operations of recorders at manifold
d. Proper operation of communication equipment, to platform, instruments required for shipboard connections and discharge, etc.

(3) Mooring system

Continuous visual monitoring of mooring system

a. Ship breakout

Mooring hawser, floats and pickup rope

a. Snarls with floating hoses or debris
b. Chafing
c. Loss of rope floats
d. Impact damage
e. Wear
f. Corrosion

Chafing chain

a. Chafing
b. Wear
c. Corrosion
d. Wear rate/diameter of chain
e. Link dimensions

Chain support buoy and connection linkage

a. Physical damage to attachment hardware
b. Chafing chain friction damage to polyurethane shell

5.2.1.2 (Continued)

Inspection equipment for mooring system

a. Proper operation
b. Security of fasteners

5.2.1.3 Continuous Visual Inspection from Launch

OTS Components

Hose string, mooring system

Periodicity

Continuous during offloading

Inspection Method *

Visual from launch or small boat using one crewman and one inspector

Special Equipment

Lighting, oil spill detector with alarm, ultraviolet light

Safety Precautions

Launch or small boat must stay a safe distance from hose string

Inspections

1. Hose string

Floating hose string

a. Leakage
b. External damage including:

- kinking
- cracks
- stretching
- nipple corrosion
- buoyancy tanks in proper position
- bulges
- wires showing
- cuts
- abrasion
- wear
- rubber disintegration
- collapse
- safety blinker lights operating
- indentations
- crushing
- loss of buoyancy
- marine growth
- nipple defects

c. Correct configuration
d. Fouling with each other
e. Stream out and floating freely
f. Damage to floatation medium
g. Flanged joints and hoses examined for leakage stains
h. Odor from oil leakage
i. Debris
j. Looseness or loss of assemblies

Submarine hose string

a. Leakage
b. Inclination of first underwater hose section
c. Loss of assemblies

NOTE: *This inspection may be eliminated in the event that inspection methods of Section 5.3.1.1 become operational.

5.2.1.3 (Continued)

Inspection devices on hose string

a. Proper operation
b. Proper configuration
c. External damage
d. Security of fasteners

(2) Mooring System

Mooring system examined for:

a. Ship breakout

Mooring hawsers, floats and pickup rope

a. Snarls with floating hoses or debris
b. Chafing at buoy
c. Loss of rope floats
d. Impact damage
e. Wear
f. Corrosion
g. Condition of sleeve-type rope floats and urethane float stop
h. Wear of thimbles
i. Entanglement
j. Fouling
k. External damage

Chafing chains

a. Chafing
b. Wear
c. Corrosion
d. External damage

Chain support buoy and connection linkage

a. Physical damage to attachment hardware
b. Chafing chain friction to polyurethane shell
c. External damage

Inspection equipment for mooring system

a. Proper operation
b. Proper configuration
c. External damage
d. Security of fasteners

5.2.1.4 Mooring Load Monitor System

OTS Component

Mooring system

Periodicity

Continuous while ship in berth

Inspection Method

Mooring load monitor system

Special Equipment

Strain-gage mooring load monitoring system with alarms on buoy, ship and platform, continuous computer monitoring at platform control, and with recorder on buoy.

Safety Precautions

No special precautions, except for observing standards regarding electrical equipment in flammable atmospheres.

Inspections

Mooring systems

a. Excessive loading
b. Hawser loading history

5.2.1.5 Hydrostatic Tests

OTS Component

Hose string

Periodicity

Weekly

Inspection Method

Hydrostatic tests (pressure drop) of hose string at approximately 1.25 times its maximum working pressure and using a suitable hose leak detection method. Hoses to be examined with pressure on and off. Inspection should last at least a few hours.

Special Equipment

Diver inspections to be carried out if leak detected--see inspections in Section 5.2.1.7; high accuracy pressure and temperature gages, pumps; system to be blocked off

Safety Precautions

Diving regulations to be observed
Tanker not to be moored to buoy
Tests to be performed at safe hydrostatic pressures
Adequate warnings that hydrostatic test is in progress

Inspections

1. Hose string

Hose string

a. Leakage
b. Pressure drop in line
c. See event C13 for other floating hose string and submarine hose string examinations.

NOTE: 1. Hydrostatic tests should be carried out during scheduled hose string visual and diver NDT inspections.

2. Hose string must be out-of-service so test should be scheduled during normal down periods of hose string.

5.2.1.6 Dye Tracing

OTS Component

Hose string

Periodicity

Every two weeks[1]

Inspection Method

Dye tracing - Dye inserted into hose string which is at its maximum working pressure; leaks detected visually and by use of a fluorometer at hose string areas that are suspect

Special Equipment

Water left in hoses, fluorometer, device to contain a sample of fluid around hose sections

Safety Precautions

Diving regulations to be observed
Tanker not to be moored to buoy

Inspections

(1) Hose string leak

NOTE: (1) Dye tracing inspections should be carried out during scheduled hose string visual and diver NDT inspections. Periodicity may be varied somewhat without significant change in the reduction of the oil spill risk

5.2.1.7 Diver NDT and Visual

OTS Components

Hose string, mooring system

Periodicity

Weekly, 1 month, 2 months, 3 months, 6 months, after collision, after storm

Inspection Method

Diver NDT and visual

Special Equipment

Hose string to be checked while hoses are both pressurized and not pressurized

Safety Precautions

Diving regulations to be observed

Tanker not moored to buoy

Inspections

(1) Weekly (monthly--two months after hose string installation)

Submarine hose string

a. Leakage - using visual inspection and also a milk V type leak solution at suspect leakage locations (flanges, nipples, valves, etc.)
b. Telltale leakage stains on all hoses, nipples and flanges
c. Correct subsea hose configuration
   - alignment of hoses, spreader bars, etc.
   - hose descent angle
   - incorrect short radius binding
   - hoses free of debris
   - check clearance between hoses and SPM
d. Bulges or deformation of hoses
e. Tightness of nuts by hand tightening
   - looseness or loss of assemblies
   - bead float assemblies
   - hose string body (flanges, etc.)
   - rigid or flexible spreader bars
   - proper mounting of rubber keys proved along hose string length to prevent slippage
f. Miscellaneous external damage to hose string
   - cracks
   - stretching
   - wear or chafing
   - rubber disintegration

5.2.1.7 (Continued)

- collapsing
- bulges
- wires showing
- creases
- nipple corrosion
- collapse
- indentations
- crushing
- marine growth
- adhesion between nipple joint and hose

Inspection devices on submarine hose string

a. Proper operation
b. Proper configuration
c. External damage
d. Security of fasteners

(2) Monthly

Submarine hose string

a. Check of bolt tightness with torque wrench

- hose flange nuts
- 10% of miscellaneous bolts and nuts

b. Seal leak detector inspection (if available) at hose flanges and hose nipples
c. Magnetic foil or magnetic rubber inspection of 10% of hose nipples
d. Cathodic protection inspection of hoses using manufacturer's recommendations

- nipples
- flanges
- etc.

Hose pickup rope inspected by divers or under-running

a. Examine strap
b. Condition of eye splices and shackles
c. Insure shackles are properly moused and pins are not worn down
d. Physical damage
e. Apparent loss of buoyancy
f. Free floating in water

Butterfly valve, ball valves and miscellaneous valves

a. Leakage
b. Impact damage
c. Corrosion

5.2.1.7 (Continued)

d. Paint deterioration
e. Operate valve and check for leakage
f. Check valve operational characteristics

<u>Mooring equipment</u>

a. Examine mooring line by divers or under-running

- security of lace on rope floats
- condition of servings and grommets
- general condition of sleeve-type rope floats and urethane float stops
- wear of thimbles
- chafing damage
- wear

b. Examine pickup rope by divers or under-running

- chafing damage
- abrasion change
- floatation

3. Two months

<u>Floating hose string</u>

a. Tightness of nuts by torque wrench

- every nut at connection of floating hose to SPM buoy or SPM fluid swivel
- 10% of nuts on the flange of each floating hose and pigtails
- seal leak detection (if available) at 10% of hose flanges and hose nipples
- magnetic foil or magnetic rubber inspection of 10% of hose nipples

b. Cathodic protection inspection on floating hoses using manufacturer recommendations

- flanges
- nipples

<u>Mooring equipment</u>

a. Hawser damage

- Measure hawser length--if more than 20% increase in length replace

5.2.1.7 (Continued)

- X-ray sections of hawsers that appear damaged for examination of internal sections of hawser

b. Chafing chain damage

- Measure wear rate/diameter of chain
- Measure chain length--if greater than 3% replace
- Measure chain links
  - -size
  - -corrosion
- X-ray chain sections that are suspected of damage
- Cathodic protection inspection (if cathodic protection exists) of chain using manufacturer's recommended schedule

(4) Six months

<u>Submarine hose string and floating hose string</u>

a. Remove marine growth
b. Measure elongation of hoses

(5) After storm or collision

Complete inspection of all components

5.2.1.8 Hose Replacement

OTS Components

Tail hose, first hose off CALM buoy, first hose off fluid swivel for SALM

Periodicity

Six months

Replacement

Replace hose

Special Equipment

Only standard equipment required

Safety Precautions

No special precautions

Inspections

(1) Inspect hose onshore

- Reinstall if hose is in excellent condition
- Save hose for spare if in good condition
- Reject hose after one year of use

NOTE: Replacement schedule may vary depending upon conditions such as

- frequency of vessel calls
- loading history
- bad weather, storms, collisions
- DWP environmental conditions
- results of other inspections while installed

5.2.1.9 Hose String Replacement

OTS Components

Floating hose, string, submarine hose string

Periodicity

One year

Replacement

Replace hose string

Special Equipment

Only standard equipment required

Safety Precautions

No special precautions

Inspections

Inspect hose onshore

- Reinstall if hose is in excellent condition
- Save hose for spare if in good condition
- Reject hose after two years of use

NOTE: Replacement schedule may vary depending upon conditions such as:

- frequency of vessel calls
- bad weather, storms, collisions
- DWP environmental conditions
- results of other inspections while installed

5.2.1.10 Hawser Replacement

OTS Component
Hawser

Periodicity
6 months

Replacement
Replace hawser

Special Equipment
Only standard equipment required

Safety Precautions
No special precautions

Inspections
Record damage and areas showing wear

NOTE: Replacement schedule may vary depending upon conditions such as:

- loading history
- bad weather, storms, collisions
- DWP environmental conditions
- results of other inspections of hawser
- frequency of vessel calls

5.2.2 Undersea Pipeline

Recommended inspection methods for the undersea pipeline include the following:

1. Pipeline - Rupture
   - Sonar - sidescan and penetrating (see Section 5.2.2.1)
   - Hydrocarbon probe (see Section 5.2.2.2)
   - Charting (see Section 5.2.2.3)
   - Hydrostatic (pressure drop) (See Section 5.2.2.4)
   - OTS control - mathematical modeling (see Section 5.2.2.5)
   - Inspection pig
     a. Kaliper (see Section 5.2.2.6a)
     b. Magnetic flux (See Section 5.2.2.6b)
   - Corrosion flow sampling (see Section 5.2.2.7)
2. Pipeline - Corrosion, Weld Defects
   - Hydrocarbon probe (see Section 5.2.2.2)
   - Hydrostatic (pressure drop) (see Section 5.2.2.4)
   - Inspection pig
     b. Magnetic flux (see Section 5.2.2.6b)
   - Corrosion flow sampling (see Section 5.2.2.7)
3. Pipeline - Cathodic Protection
   - Manufacturer's inspection schedule and maintenance program (see Section 5.2.2.8)
   - Inspection pig
     b. Magnetic flux (see Section 5.2.2.6b)

A recommended schedule of these inspections is given in Table 5-2 and inspection methods and procedures are described in detail in subsections that follow.

TABLE 5-2 RECOMMENDED SCHEDULE FOR INSPECTIONS AND REPLACEMENTS OF OTS COMPONENTS FOR UNDERSEA PIPELINE

OTS COMPONENT	SHIP IN BERTH				PERIODICITY (1)															
	Before	During Off Loading		After	Cont.	Hours		Days	Weeks		Months				Years			Once Per Ship	After	
		Yes	No			2	8	1	1	2	1	2	3	6	1	3	5		Storm	Colli-sion
UNDERSEA PIPE-LINE		X										5.2.2.1				5.2.2.3				
				X								5.2.2.2		5.2.2.6						
	X	X	X	X	5.2.2.5															
		X			5.2.2.7				5.2.2.7		5.2.2.7									
			X					5.2.2.8			5.2.2.8				5.2.2.8					
			X												5.2.2.4					
	X	X	X	X	5.3.2.1															
		X												5.2.2.2						

(1) For recommended inspection or replacement event, see the Section identified.

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Inspection of the undersea pipeline between the platform and shore is extremely important because the spill risk in barrels per year (1000) is quite high, but more importantly, very large spills are possible (Table 4-1). The same also is true for the SPM pipeline. It is estimated that implementation of the recommended procedures should reduce the relative risk of barrels of oil spilled from 1000 to about 100 bbls.

100 bbls.

At the present time, no inspection methods currently in use are capable of adequately inspecting the inside of the undersea pipeline for incipient failure detection. Internal pipeline inspections are extremely important for reducing oil spill risks, particularly for buried, undersea pipeline because it is extremely difficult to inspect the pipeline externally; NDT diver inspection costs are too high for practical considerations. Inspection pigs are normally used for internal inspections. They provide good incipient failure detection, but existing inspection pigs are too small for the 54-inch diameter pipeline. Also there is expected to be relatively few miles of 54-inch diameter compared to other sizes, for example 48-inch diameter. Hence facilities with these large diameter pipelines will either have to financially support the building of larger diameter inspection pigs or pay high costs (in comparison with existing costs for smaller diameter pipelines) for inspection services.

Assuming inspection pigs will be available, it is recommended that the pipeline be inspected by an inspection pig before the line becomes operational. This will provide background (or reference) data of an undamaged pipeline and will be extremely beneficial in interpreting data from later inspections using inspection pigs.

Currently, no provisions have been made for the use of inspection pigs in the SPM pipelines, hence existing internal inspection methods for this pipeline would not be used. Also, the fact that the pipeline is coated with concrete and is buried in 10 feet of soil essentially eliminates external inspections. Under these circumstances the only inspection method that appears to be useful in reducing oil spill risk is hydrostatic testing. Based on these considerations, it is recommended that provisions be made for the use of inspection pigs in the SPM

pipelines. Inspection pigs that can go in both directions (these are available) would eliminate the cost of providing a pig receiver or launcher at the PLEM.

Recommended corrosion flow sampling is an important internal pipeline inspection method. Unfortunately it can provide only trends of internal piepline corrosion. The method was judged to decrease oil spill risk only slightly if current practices alone are followed. Significant reductions of the oil spill risk may be attained, however, if the following typical guidelines are used:

(1) Use well maintained and high-quality instruments;
(2) Use qualified personnel to monitor and record data;
(3) Maintain and analyze (possibly by computer) data records.

Other recommended and currently used inspection methods, which provide some reduction in the oil spill risk, are highly cost effective and low cost. Periodic inspections of the pipeline for exposed surfaces or incorrect soil coverage using a towed sonar system with sidescan and penetrating echo is highly effective in minimizing external pipeline damage. Periodic mapping inspection, although less effective, includes inspection of pipeline movement, scour and exposed surface. This inspection further helps to reduce the risk from external pipeline damage. An OTS control system using a mathematical modeling approach is effective in improving the sensitivity of leak detection beyond the capability of planned OTS product monitoring systems. This method was judged to be the most cost effective of the recommended inspection methods. Periodic inspections using a towed hydrocarbon probe provides for some detection and location of small incipient type leaks that may preceed rupture. This method is very effective for inspection of small leaks caused by corrosion or weld defects.

Cathodic protection inspection is also recommended. Strict adherence to manufacturer's recommended inspection schedules and procedures is necessary to maintain adequate protection against pipeline external corrosion.

5.2.2.1 Sonar Survey (Sidescan and Penetrating)

OTS Component
Pipeline

Periodicity
Every two months

Inspection Method

Survey pipeline with a sonar system installed inside a towfish to locate bare spots and correct depth of soil overburden. Inspection includes transducers and equipment for both pulsed horizonal side-scan and penetrating and non-penetrating vertical acoustical beams. Fish is towed a few meters above soil.

Special Equipment
Launch or small boat with winch to pull the towfish with sidescan and penetrating sonar system, data retrieval and analyzing equipment, pressure transducer to monitor depth

Safety Precautions
No special precautions

Inspections

(1) Pipeline

a. Detection and location of pipeline bare spots
b. Detection and location of incorrect burial of pipeline

NOTE: This inspection should be carried out at the same time as that in Section 5.2.2.2 (hydrocarbon probe inspections) in order to minimize inspection costs.

5.2.2.2 Hydrocarbon Probe

OTS Component
Pipeline

Periodicity
Two months

Inspection Method
Survey pipeline with a towfish that contains a hydrocarbon probe for oil leak detection and a pressure transducer to monitor depth. Fish is towed a few meters above soil.

Special Equipment
Launch or small boat with winch to pull the two fish, hydrocarbon and pressure transducer towfish, pressure monitor and hydrocarbon monitor

Safety Precautions
No special precautions

Inspections

(1) Pipeline

a. Oil leakage - detection and location

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5.2.2.3 Charting

OTS Component

Undersea pipeline

Periodicity

Two years

Inspection Method and Procedures*

Diver walks line with a very narrow beam acoustic transponder, a pneumofathometer and a penetrating and non-penetrating acoustical pulse-echo device

Special Equipment

Diving equipment, transponder, receiver, buoy

Safety Precautions

Diving regulations to be observed

Inspections

1 Pipeline undersea

a. Location
b. Damage
c. Scour
d. Depth of burial
e. Bare spots

Note: * Other inspection methods and procedures from surface vessels are available that do not require the use of the diver, but these do not detect and measure pipeline damage or scour. However, use of a submersible or remotely piloted vehicle may be adequate.

5.2.2.4 Hydrostatic Pressure Drop

OTS Component
    Undersea and underground pipeline

Periodicity
    Yearly

Inspection Method and Procedures
    Hydrostatic tests (pressure drop) of pipeline are conducted at a high, safe pressure and using a suitable leak detection method if a leak is indicated. Inspection should last about 24 hours.

Special Equipment
    High accuracy pressure and temperature monitors, pumps, leak location equipment, pipeline must be blocked off

Safety Precautions
    Tests to be performed at safe hydrostatic pressure
    Pipeline must be out-of-service
    Adequate warnings that a hydrostatic test is in progress

Inspections

1. Pipeline

    a. Oil leakage

5.2.2.5 OTS Control Mathematical Modeling

OTS Component
Undersea and underground pipeline - rupture and other damage

Periodicity
Continuous

Inspection Method and Procedures
OTS control using mathematical modeling for leak detection inspection - computerized model OTS system including effects of size and materials of components, and flow characteristics (time, pressure, flow, visiosity, etc.)

Special Equipment
Computer system to be adapted to OTS supervisory control system; required flow characteristic measurements at stipulated locations

Safety Precautions
No special precautions

Inspections

(1) Pipeline

a. Small to medium leaks that will, if undetected, lead to rupture
b. Early rupture detection

5.2.2.6.a Inspection Pig - Kaliper Type

OTS Component
Undersea pipeline

Periodicity
Every six months

Inspection Method and Procedures

- Kaliper inspection pig propelled through pipeline by fluid flow
- Inspection should be carried out after pipeline is cleaned by a good, high quality cleaning pig
- Inspection should be scheduled when pipeline is normally out-of-service to minimize cost
- Inspection should be carried out just before inspection that in Section 5.2.2.6.b to reduce cost and increase inspection reliability
- Inspection should be carried out by a qualified inspection service

Special Equipment
Pig sending and receiving traps, pumps, pressure and flow monitors, locator device on inspection pig

Safety Precautions
No special precautions

Inspections

1. Pipeline

   a. Changes in diameter
   b. Buckles
   c. Dents
   d. Changes in wall thickness
   e. Flat spots, bends
   f. Partially closed valves
   g. Miscellaneous

NOTE: This inspection is also recommended before the pipeline becomes operational for background and reference data.

5.2.2.6.b Inspection Pig - Magnetic Flux Type

OTS Component
Undersea pipeline

Periodicity
Every six months

Inspection Method and Procedures
- Magnetic flux inspection pig propelled through pipeline by fluid flow
- Inspection should be carried out after pipeline is cleaned by a good, high quality cleaning pig
- Inspection should be scheduled after inspection by Kaliper inspection pig, to reduce costs and increase inspection reliability
- Inspection should be carried out by a qualified inspection service

Special Equipment
Pig sending and receiving traps, pumps, pressure and flow monitors, locator device on inspection pig

Safety Precautions
No special precautions

Inspections

(1) Pipeline

a. Corrosion severity
b. Hardspots
c. Manufacturer defects
d. Cathodic protection
e. Improper bends
f. Gouges
g. Wrinkles
h. Hydrogen blisters
i. Bends
j. Pitting
k. Miscellaneous

NOTE: This inspection is also recommended before the pipeline becomes operational for background and reference data.

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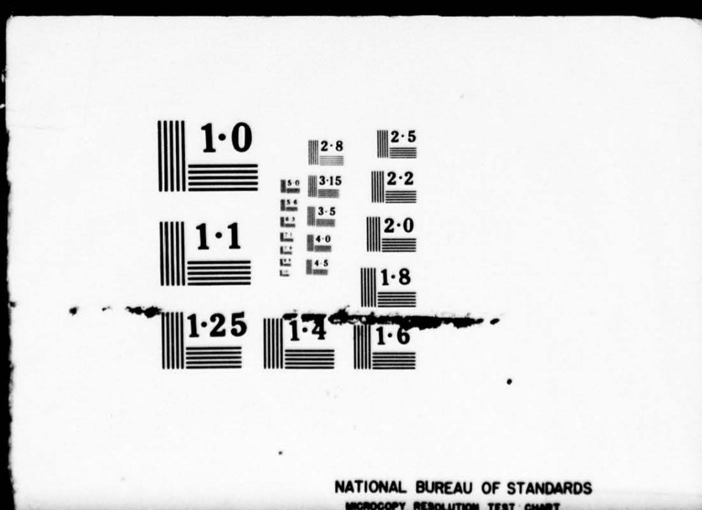

5.2.2.7 Corrosion Flow Sampling

OTS Component
Undersea and underground pipeline

Periodicity
Continuous, weekly, monthly

Inspection Method and Procedures
Continuous - corrosion rate probe installed inside pipeline and examined weekly
Weekly - Laboratory analysis of contents in flow of
- iron
- oxygen
- inhibitor
- sediment
- etc.

Weekly - Monitoring of strainer contents, etc.
Monthly - Corrosion rate coupons, installed at inlet and outlet of pipelines, examined
Bi-annually - Examinations of pig trap returns after pigging

Special Equipment
Laboratory analyzing equipment, corrosion rate coupons, corrosion rate probe, monitoring and sampling equipment

Safety Precautions
No special precautions

Inspections

1. Pipeline

   a. Internal pipeline corrosion trends
   b. Miscellaneous internal damage that causes particles to break off and to be carried onshore by the flow

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5.2.2.8 Cathodic Protection Inspection

OTS Component

Undersea and underground pipeline

Periodicity

Daily, monthly, yearly

Inspection Method and Procedures

Manufacturer's recommended inspection and procedures should be followed:

- Potential measurements by a diver
- Anode condition, and the size and depth of pits and cracks

Special Equipment

Alarm systems for proper voltage and amperage of impressed current

Safety Precautions

Diving regulations to be observed

Inspections

(1) Daily

a. Impressed current systems are checked daily for the proper voltage and amperage

(2) Monthly

a. Platform to water potential reading at permanent platform reference points

(3) Yearly*

a. Pipeline potential readings

b. Exact count and estimation of wastage

c. Check anode condition

- size and depth of pits and cracks
- security of anode to mountings
- damage
  - chipping
  - holes
  - check insulating flanges

d. Remove excess marine growth

NOTE: * For buried, underground and undersea pipeline, inspection items 3b, 3c and 3d may be performed over a longer period, e.g., 5 years, on sample sections.

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5.2.3 SALM SPM

Recommended inspections and replacements for the OTS components of the SALM SPM include the following:

- Visual inspection on buoy (see Section 5.2.3.1)
- Diver NDT and visual inspection of SALM components (see Section 5.2.3.2)
- Manufacturer's recommended inspection methods and procedures of SALM OTS components (see Section 5.2.3.3)
- SALM-SPM removed for onshore inspection (see Section 5.2.3.4)
- Dye tracing of fluid swivel and hose arm (see Section 5.3.1.5)

A recommended schedule of these inspections is given in Table 5-3. Inspection methods and procedures are described in detail in subsections that follow.

The SALM SPM must be inspected thoroughly throughout the year because of the possibility of OTS component oil leakage (spill risk about 35 barrels per year) and the possibility of SALM SPM external component breaks (from buoy to PLEM). These breaks can cause the SALM to separate, cause ship breakout and result in hose rupture (oil spill risk about 150 barrels per year). Recommended inspections of the hose arm and fluid swivel (primarily by diver visual and NDT and by dye tracing), should insure that the oil spill risks can be reduced significantly (about a factor of 10). However, visual inspections on the buoy and manufacturer's recommended inspections and maintenance procedures, particularly for the fluid swivel, also should be carried out.

The cost-effectiveness of these inspection methods and procedures is quite low. However, there appear to be no other more cost-effective inspection methods and procedures. In general, most of the inspection methods and procedures included here are carried out on SPMs at well-maintained DWP facilities. It would be unwise to exclude these inspections because of cost considerations, alone.

TABLE 5-3 RECOMMENDED SCHEDULE FOR INSPECTIONS AND REPLACEMENTS OF OTS COMPONENTS FOR SALM SPM

OTS COMPONENT	SHIP IN BERTH				PERIODICITY (1)															
	Before	During Off Loading		After	Cont.	Hours		Days	Weeks		Months				Years			Once Per Ship	After	
		Yes	No			2	8	1	1	2	1	2	3	6	1	3	5		Storm	Collision
SALM SPM (Mooring buoy fluid swivel, hose arm, riser shaft, PLEM, mooring base)	X			X				5.2.3.1			5.2.3.1		5.2.3.1					5.2.3.1	5.2.3.1	5.2.3.1
				X							5.2.3.2		5.2.3.2	5.2.3.2				5.2.3.2	5.2.3.2	5.2.3.2
				X		(5.2.3.3 as required)														
				X													5.2.3.4			

(1) For recommended inspection or replacement event, see the Section identified.

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5.2.3.1 Visual on Buoy

OTS Component
Mooring buoy

Periodicity
Before ship visit, weekly, 1 month, 3 months or after storm or after collision

Inspection Method
Visual on buoy

Special Equipment
Only standard equipment required

Safety Precautions
No special precautions

Insepctions

(1) Before ship visit

Buoy components

a. Radar reflector

- security of fastenings
- damage

b. Obstruction light

- operating

(2) Each week

Buoy components

a. Mooring bracket

- effectiveness
- deterioration
- security of fasteners
- corrosion
- physical damage
- NDT

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5.2.3.1 (Continued)

b. Pins

- effectiveness
- pin dimension measurement
- deterioration
- corrosion
- physical damage

c. Hawser thimble

- effectiveness
- deterioration
- corrosion
- physical damage

3. Each month

Buoy Components

a. Manhole covers

- physical damage
- gasket damage
- corrosion
- water tightness

b. Compartment water tightness

- complete examination of buoy body compartments - if water in any compartments, check

  - sounding air vent plugs
  - flooding valves
  - piping hull penetrators
  - welds

c. Bulge/sump pump

- check operation

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5.2.3.1 (Continued)

d. Mooring bracket

- NDT, magnetic particle or ultrasonic

e. Mooring pins

- NDT - liquid penetrants

f. Hawser thimble

- NDT - liquid penetrants

g. Fenders above low water level

- condition of fenders
- security of fasteners

h. Paint

- damage to protective coating or structure
- deterioration of protective coating
- debris
- fouling

4. Three months

Buoy Components

a. Buoy body above water line

- inspect damage
- paint deterioration (repaint affected areas)
- corrosion
- security of fasteners

b. Buoy ladders

- external damage
- security of fasteners

5.2.3.2 Diver NDT and Visual

OTS Component
Mooring buoy, fluid swivel, hose arm, riser shaft, PLEM, mooring base, and connection between main components *

Periodicity
1 month, 3 months, 6 months, or after storm or collision

Inspection Method
Diver NDT and visual

Special Equipment
Diving equipment, inspection equipment--ultrasonics, magnetic foil, calipers, gamma-ray, torque wrench, pneumofathometer

Safety Precautions
Tanker not moored to buoy
All diving regulations observed

Inspections

1. Monthly

Buoy Components

a. Condition of submerged fenders
   - securing of fenders

b. Condition of submerged surfaces of buoy hull unprotected by fenders
   - external damage
   - deterioration of protective coating
   - coating
   - extent and nature of marine growth

Hose arm

a. Connections
   - leakage
   - hose connection must conform to specified length requirement
   - adequate clearance between bumper rail and hose for absence of kinking

*Buoy universal joint, anchor chain attachment bracket, anchor chain, chain swivel, shaft universal joint, connector-universal joint to fluid swivel, bolts

5.2.3.2 (Continued)

b. Upper and lower buoyancy tanks

- check tanks are in proper position
- corrosion
- damage
- security of fasteners

(2) Three months

Buoy Components

a. Buoy anodes

- check condition
- indicate percent of consumption
- cleanliness
- extent and nature of marine growth
- security of anodes to mountings
- external damage

Hose arm

a. Inclination and clearance to bumper rail

- check for proper clearance between bumper rail and resilient bumper
  - adjustment should preferably be made by removing water from buoyancy tank at low end, if no water at low end, add water to high end

b. Ball valves and miscellaneous valves

- check for leakage
- operate valve and check valve characteristics
  - opening time
  - closing time
  - fully open
  - fully closed
- corrosion
- physical damage
- tighten bolts with torque wrench

External buoy components

a. All bolts and fasteners

- check tightness with torque wrench

b. Universal joints - buoy and base

- damage or loss of components
- bearing material not being ejected from housing
- inspect with magnetic particle or gamma-ray(welds,etc)

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5.2.3.2 <u>(Continued)</u>

- check corrosion
- check wear rate and compare with previous inspection
- extent and nature of marine growth
- examine webs and brackets for fairness and freedom from buckling
- check bolt tightness

c. Anchor chain attachment bracket

- examine bracket with magnetic particle (or magnetic rubber, if available) or gamma-ray inspection
- measure rate of wear and compare with previous inspection
- check tightness of bolts
- check corrosion

d. Anchor chain

- measure length of chain links
- check corrosion
- check for external damage
- extent and nature of marine growth

e. Chain swivel

- degree of twist of chain necessary to rotate swivel
- comparison of angle of twist with previous inspection

f. Connector between universal joint and fluid swivel

- seating of U-joint base plate on top of product center shaft
- seating of locking caps for key lock bolts
- corrosion
- external damage
- extent and nature of marine growth
- examine with magnetic particle, gamma-ray or ultrasonic

<u>Riser</u>

a. Product transfer pipe

- seated properly in supports
- check for leakage
- check condition of anodes for
  - wastage
  - cleanliness
  - external damage
  - extent and nature of marine growth
  - corrosion
  - security of anodes to mountings

5.2.3.2 (Continued)

- fouling
- corrosion
- damage

b. Housing

- external damage
- corrosion
- check thickness with NDT active ultrasonics
- extent and nature of marine growth
- fouling

c. Bolts

- check bolt tightness with torque wrench

Mooring base

a. Anodes

- wastage
- cleanliness
- external damage
- extent and nature of marine growth
- corrosion
- security of fasteners
- fouling

b. Siltation level

- measure siltation level from the lower flange of the lowest swivel joint

Liquid swivel assembly

a. Skirts

- check integrity

b. Proper greasing procedures have been carried out

(3) Six Months

Mooring buoy

a. Mooring table welds (CALM)

- examine 10% of highly stressed welds for fatigue cracking by NDT methods (primarily active ultrasonics or magnetic particle)

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5.2.3.2 (Continued)

b. Ladder equipment

- rope grip to be checked

Hose arm

a. Resilient bumpers under buoyancy tanks

- check for proper condition
- external damage
- security of fasteners
- corrosion
- marine growth

Liquid swivel assembly

a. Gasket seals

- leakage at
  - flange joint between swivel joints and swivel housing
  - exterior clearance between the stationary and moving parts of each swivel joint
- uniform gap between retaining ring and top of upper fluid swivel joint

b. All horizontal and vertical swivel joints

- leakage while under operating conditions

c. Brackets between upper and lower swivel housing

- excessive torque resistance of upper swivel assembly
  - deformation of guiding brackets
  - dislocation of guiding brackets

d. Rotation of upper and lower swivel housing

- free rotation of the hose and hose arm around the buoy
- examine tendency of hose to kink during rotation around the buoy
- examine tendency of hose to be unduly strained during rotation around the buoy

e. Remove all marine growth

PLEM

a. Valves

- check for leakage
- operate valve and check characteristics

5.2.3.2 (Continued)

-opening time
-closing time
-fully open
-fully closed

- corrosion
- physical damage
- tightness of bolts
- extent and nature of marine growth

b. Piping

- leakage
- external damage
- corrosion
- examine using NDT - active ultrasonics and magnetic foil
- tighten bolts with torque wrench
- extent and nature of marine growth

c. Chamber

- leakage
- external damage
- corrosion
- marine growth
- examine using NDT - active ultrasonics and magnetic foil
- tighten bolts with torque wrench
- marine growth

d. Flanges and gaskets and seals

- leakage
- external damage
- corrosion
- examine using NDT - active ultrasonics, magnetic foil, seal leak detector milk-type solution
- tighten bolts with torque wrench

Mooring base

a. Piping

- leakage
- external damage
- corrosion
- examine using NDT - active ultrasonics and magnetic foil
- tighten bolts with torque wrench
- extent and nature of marine growth

5.2.3.2 <u>(Continued)</u>

b. Bolted connections of fluid swivel assembly to mooring base structure

  - check for bolt tightness with a torque wrench

c. Bumper rail

  - remove marine growth to reduce friction between hose arm bumper and bumper rail

d. Base

  - inspect perimeter of base for scour
    - visual
    - pneumofathometer

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5.2.3.3 <u>Manufacturer's Recommended Inspection Methods and Procedures of SALM OTS Components</u>

<u>OTS Component</u>
All SALM components

<u>Periodicity</u>
See manufacturer's recommendations

<u>Inspection Method</u>
See manufacturer's recommendations

<u>Special Equipment</u>
See manufacturer's recommendations

<u>Safety Precautions</u>
See manufacturer's recommendations

<u>Inspections</u>
See manufacturer's recommendations

5.2.3.4 SALM SPM Removal for Onshore Inspection

OTS Component
SALM SPM

Periodicity*
5 years

Inspection Method
Removal for on-land inspections

Special Equipment
Only standard equipment required

Safety Precautions
No special precautions

Inspections
(1) SALM SPM
Manufacturer's recommended inspection and maintenance

NOTE: * Removal schedule for on-land inspections may vary depending upon conditions such as

- bad weather, storms, or collisions
- high usage
- DWP environmental conditions
- results of other inspections while installed
- miscellaneous

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5.2.3.5 Dye Tracing

OTS Component
Fluid swivel assembly and hose arm

Periodicity
2 months

Inspection Method
Dye tracing

Special Equipment
See Section 5.2.1.6

Safety Precautions
See Section 5.2.1.6

Inspections
See Section 5.2.1.6

5.2.4 CALM SPM

Recommended inspection and replacements for the OTS components of the CALM SPM include:

- Visual and NDT inspections on the buoy (see Section 5.2.4.1)
- Diver NDT and visual inspections of CALM OTS components (see Section 5.2.4.2)
- Manufacturer recommended inspection methods and procedures of CALM components (see Section 5.2.4.3)
- CALM SPM removal for onshore inspection (see Section 5.2.4.4)
- Underbuoy Hose String inspections - same as those for the submarine hose string - see Section 5.2.1

The CALM SPM must be inspected thoroughly throughout the year because of the moderate risk of oil leakage (about 66 barrels per year) from OTS components and the high risk of oil spills (about 750 barrels per year) from the underbuoy hose string. The recommended inspections of the CALM SPM, excluding those for the underbuoy hose string, are expected to decrease the oil spill risk only moderately (about 25%). These recommended inspections now are normally carried out at well-maintained DWP facilities.

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TABLE 5-4 RECOMMENDED SCHEDULE FOR INSPECTIONS AND REPLACEMENTS OF OTS COMPONENTS FOR CALM SPM

OTS COMPONENT	SHIP IN BERTH				PERIODICITY (1)															
	Before	During Off Loading		After	Cont.	Hours		Days	Weeks		Months				Years			Once Per Ship	After	
		Yes	No			2	8	1	1	2	1	2	3	6	1	3	5		Storm	Colli-sion
CALM SPM (Mooring buoy, product distribution unit, rotating deck, underbuoy hose string*, PLEM, PLEM anchor base, chain anchors)	X			X					5.2.4.1		5.2.4.1		5.2.4.1		5.2.4.1			5.2.4.1	5.2.4.1	5.2.4.1
				X					5.2.4.2				5.2.4.2	5.2.4.2	5.2.4.2				5.2.4.2	5.2.4.2
				X		5.2.4.3	(see manufacturer recommendations)													

* See submarine hose string inspection methods and periodicity Section 5.2.1.

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5.2.4.1 Visual and NDT Inspections of Buoy

OTS Component
Mooring buoy

Periodicity
Before ship visit, weekly, 1 month, 3 months, yearly or after storm or collision

Inspection Method
Visual and NDT

Special Equipment
Inspection equipment - ultrasonics, magnetic foil, calipers, gamma-ray, torque wrench, etc.

Safety Precautions
No special precautions

Inspections

1. Before ship visit

   Buoy examined for:

   a. Anchor lines

      - check positioning of buoy

   b. Obstruction light

      - exercise to insure operable condition
      - security of fasteners
      - damage

2. Each week

   Mooring buoy examined for:

   - Physical damage
     - cracks
     - buckling
     - holes

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5.2.4.1 (Continued)

- corrosion
  - check operation of any corroded moving component

b. Product distribution unit

- physical damage
  - cracks
  - buckling
  - holes
- verify proper operation

c. Mooring bracket

- effectiveness
- deterioration
- security of fasteners
- corrosion
- physical damage

d. Pins

- effectiveness
- pin dimension measurement
- deterioration
- corrosion
- physical damage

e. Hawser thimble

- effectiveness
- deterioration
- corrosion
- physical damage

f. Product distribution unit

- physical damage
  - cracks
  - buckling
  - holes
- verify operation

5.2.4.1 (Continued)

(3) Each month

Buoy

a. All structural components

- physical damage
  - cracks
  - buckling
  - holes
- check for fouling
- inspect anu repair all paint damage
- corrosion
  - check operation of any corroded mooring component
- check for debris
- security of fasteners

b. Buoyancy compartments

- check manhole covers and hatches
  - water tightness
  - gasket damage
  - corrosion
- sound buoyancy compartment
- pump out all water in compartment; if water in any compartment check
  - sounding air vent plugs
  - flooding valves
  - piping hull penetrator
  - welds
- security of fasteners

c. Obstruction light

- exercise to insure operable condition
- security of fasteners
- corrosion
- damage
- inspect for scratches on lens or damage to lens and replace as necessary
- check assembly for water tightness
- check power output of batteries

5.2.4.1 (Continued)

d. Radar reflector

- security of fastener
- damage
- corrosion

e. Mooring bracket

- NDT - magnetic particle or ultrasonic

f. Mooring pins

- NDT - liquid penetrants

g. Hawser thimble

- NDT - liquid penetrants

h. Product distribution unit

- corrosion
  - thorough visual examinations for corrosion
  - check improper operation of corroded moving component

i. Turntable roller bearing

- drain turntable roller bearing chamber
  - depending on volume of drain-off, inspect appropraite seals as necessary
- lubricate turntable roller bearing
- check all bolt tightness
- grease

j. Mooring arm and unloading and balancing arm

- lubricate ball bearing
- grease rotating joints

k. Valves

- check for leakage
- operate valve and check valve characteristics
  - operating time
  - closing time
  - fully open
  - fully closed
- corrosion
- physical damage
- tightness of bolts

5.2.4.1 (Continued)

l. Control pipe swivel unit

- check all bolt tightness
- lubricate
- grease

m. Winch motor and hoisting equipment (should be stored ashore and only used when necessary)

(4) Every three months

Buoy

a. Product distribution unit (with cargo hoses pressurized)

- inspect for leaks
  - visual
  - seal leak detector
- replace seals as necessary

b. Product distribution unit (with cargo hoses pressurized and dye inserted)

- inspect for leaks
  - visually

c. Expansion pieces

- inspect interior of expansion unit
- replace as necessary

d. Anchor chains

- lost pretension
- chain wear close to underside of fender and skirt
- replace as necessary
- exercise chain stopper

(5) Yearly

Buoy

a. Anchor chain (disconnect one chain and bring to surface for thorough inspection)

- wear
- cracks
- chain lenght (replace if length increased by 5%)
- chain link diameter (replace if diameter decreased by 5%)

5.2.4.1 <u>(Continued)</u>

- corrosion
- NDT inspection of suspect areas
  - liquid penetrants
  - x-ray inspection
- replace as necessary

5.2.4.2 Diver NDT and Visual Inspections of CALM Components

OTS Component
Mooring buoy, anchor chains, PLEM, Mooring base

Periodicity
1 week, 3 months, 6 months, yearly or after storm or collision

Inspection Method
Diver NDT and visual

Special Equipment
Diving equipment, inspection equipment - ultrasonic, magnetic foil, torque wrench, pneumofathometer

Safety Precautions
Tanker not moored to buoy
All diving regulations observed

Inspections

(1) Weekly

Anchor chains

- check nuts on clamps on anchor chains

(2) Three months

Buoy

a. Buoy anodes
- check condition
- indicate percent of consumption
- cleanliness
- extent and nature of marine growth
- security of anodes to mounting
- external damage

b. Anchor chains

- check chain wear and stopper conditions under buoy of one chain
- check one chain buoy to sea bottom for wear
- read chain angles

c. Mooring base

- anodes
  - wastage
  - cleanliness

5.2.4.2 (Continued)

- external damage
- extent and nature of marine growth
- corrosion
- security of fastening
- bolt tightness with torque wrench

(3) Six months

PLEM

a. Valves

- check for oil leakage
- operate valve and check valve characteristics
  - opening time
  - closing time
  - fully open
  - fully closed

- corrosion
- physical damage
- tightness of bolts
- extent and nature of marine growth

b. Piping

- leakage
- external damage
- corrosion
- examine using NDT - active ultrasonics and magnetic foil
- tighten bolts with torque wrench
- extent and nature of marine growth

c. Chamber

- leakage
- external damage
- corrosion
- marine growth
- examine using NDT - active ultrasonics and magnetic foil
- tighten bolts with torque wrench
- extent and nature of marine growth

Mooring base

a. Piping

- leakage
- external damage
- corrosion

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5.2.4.2 <u>(Continued)</u>

- examine using NDT- active ultrasonic and magnetic foil
- tighten bolts with torque wrench
- extent and nature of marine growth

b. Bolted connections to PLEM and underbuoy hoses

- check bolt tightness with a torque wrench

c. Base

- inspect perimeter of base for scour
  - visual
  - pneumofathometer

<u>Anchor chain piles</u>

- inspect perimeter of piles for scour
  - visual
  - pneumofathometer

<u>Buoy</u>

- survey horizontal position of buoy

(4) Yearly

<u>Anchor chain</u>

- remove one anchor chain and bring to surface for inspection

5.2.4.3 Manufacturer's Recommended Inspection Methods and Procedures of CALM OTS Components

OTS Component
All CALM OTS components

Periodicity
See manufacturer's recommendations

Inspection Method
See manufacturer's recommendations

Special Equipment
See manufacturer's recommendations

Safety Precautions
See manufacturer's recommendations

Inspections
See manufacturer's recommendations

5.2.4.4 CALM SPM Removal for Onshore Inspection

OTS Component
CALM SPM

Periodicity
5 years

Inspection Method*
Removal for on-land inspections

Special Equipment
Only standard equipment required

Safety Precautions
No special precautions

Inspections

(1) CALM SPM

Manufacturer's recommended inspection and maintenance

NOTE: * Removal schedule for on-land inspections may vary depending upon conditions such as:

- bad weather. storms, collisions
- high usage
- DWP environmental conditions
- results of other inspections while installed
- miscellaneous

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5.2.5 Offshore Platform and the Pumping and Metering Systems

Oil spill risks are quite low, about a barrel per year, for the offshore platform and pumping and metering systems. As noted previously, the risk value is low because of the secondary containment provided by the curbed decking. In view of these conditions, most inspection methods currently in use at well-maintained facilities are recommended. These include:

1. OTS components on the platform, deck, water surrounding the platform, and the oily water separator

   - Daily visual inspections of all external OTS structures and water surrounding the platform;
   - Strict adherence to the manufacturer's inspection schedules and maintenance of platform OTS components, and the pumping and metering system;
   - Control room monitoring, alarms, and shutoff of all valves, machinery and other equipment that, if not operating properly or in the incorrect operational mode, can cause an oil spill incident;
   - Redundant equipment to replace critical OTS components that can fail;
   - Oil spill detectors installed on the platform at critical locations around the structure to aid visual inspection from the platform for oil spills (detectors should be installed, for example, where the undersea pipeline connects to the platform piping);
   - Yearly NDT and visual inspections.

2. Platform Structure

   - Visual on the deck and diver visual and and NDT underwater inspections of the platform structure. On a yearly basis and after collisions, earthquakes, and severe storms.

The first five recommended inspection methods and procedures for platform components, deck and water surrounding the platform are self-explanatory and will not be discussed further. These methods may not

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produce any significant reduction in the oil spill risk per year. However, they will effectively maintain the integrity of the oil transfer system and continue to minimize the number and extent of pollution on the platform and in the water surrounding the platform.

Yearly NDT and visual inspections by inspection teams are recommended for the OTS components on the platform. These include the OTS components of the waste disposal system, oily water separation system, piping upstream from the pumps, pump section, piping downstreat from the pumps, the fire protection system and ship navigational aids. Both visual and NDT inspection should be used. The main NDT methods should include active ultrasonics, radiography (X-ray, gamma-ray and back-scatter gamma-ray--depending upon OTS component) and magnetic particle inspection of piping and vessels. Ultrasonic, radiographic and magnetic particle inspections should be used, where appropriate, on other components such as manifolds, block valves, strainers, check valves, flanges, seals, etc. The tightness of all bolts should be checked. Deck inspections should include a complete examination for corrosion, cracks or external damage in order to minimize the possibility of leakage of oil through holes in the deck. Annual inspections should be carried out at specified locations (typically about 5000) for the OTS components on the platform. Also, about 10 percent of the additional area should be inspected yearly using quick, simple methods such as visual, dye tracing and ultrasonics. In general, ultrasonics and magnetic particle inspection should be used because of their low cost. Radiographic methods should be used in areas where other methods are difficult to apply. Also, these inspections should be used when permanent, easily understood inspection records are needed for either certain critical OTS components or to follow the history of components that have defects not serious engougoh to require replacement.

The recommended annual inspection of the platform structure is essential to maintain its integrity and to effectively maintain the small relative oil spill risk of about 1.2 barrels per year shown in Table 4-1. More importantly, however, these inspection methods and procedures should attain a significant reduction in the large nominal spill size (4000 barrels of oil) that could be caused by damage to

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the platform. Annual, visual and NDT inspections recommended include the following:

- Visual inspection of the entire structure;
- Removal of marine growth from all major weld areas for visual inspection of cracking, corrosion or other damage;
- Examination of 10 percent of the weld areas using NDT inspection, foil or magnetic particle is recommended
  - if damage is noted, examine severity of defect by ultrasonic inspection,
  - if damage is severe enough to possibly warrant repair, inspect with radiographic or ultrasonic imaging;
- Measure wall thickness of 10 percent of tubular members with ultrasonic inspection to check for corrosion damage;
- Inspect corrosion inhibiting system;
- Map marine growth, scour and debris;
- Examine riser with ultrasonic inspection and check tightness of all clamps and bolts.

If inspections indicate extensive damage caused by defective welds, corrosion, structural damage, etc., a complete examination of the platform structure should be carried out. Underwater inspections by divers and support personnel should use the following general procedure.

(1) Inspection surveys should be recorded by videotape photographs or other equivalent techniques and a written report submitted that includes,

- structure description
- inspection methods and techniques used
  - specific areas of platform inspected
- inspection results (include specific location) of
  - damage
  - corrosion
  - pitting
  - weld damage

- map of marine growth, scour, debris
- condition of corrosion inhibiting system
- weather conditions;

(2) High pressure cleaning, wire brush, sanding, etc. should be performed on underwater components (typically 10 percent) of the structure that are inspected by NDT and visual techniques;

(3) All applicable U. S. diving regulations and procedures for offshore facilities will be followed.

5.2.6 Onshore Pipeline and Appurtenances

Recommended inspection methods and procedures for the onshore pipelines and appurtenances include the following:

(1) Underground Pipeline - Rupture

- Visual (see page 5-74)
- Hydrostatic (see Section 5.2.2.4)
- OTS control - mathematical modeling (see Section 5.2.2.5)
- Inspection pig
  - Kaliper (see Section 5.2.2.6a)
  - Magnetic flux (see Section 5.2.2.6b)
- Corrosion flow sampling (see Section 5.2.2.7);

(2) Underground Pipeline - Corrosion, Weld Defects

- Hydrostatic (pressure drop) (see Section 5.2.2.4)
- Inspection pig
  - Magnetic flux (see Section 5.2.2.6b)
- Corrosion flow sampling (see Section 5.2.2.7);

(3) Underground Pipeline - Cathodic Protection

- Manufacturer's inspection schedule and maintenance program (see Section 5.2.2.8)
- Inspection pig
  - Magnetic flux (see Section 5.2.2.6b);

(4) Aboveground Pipeline (Rupture, Corrosion, Weld Defects)

- Visual (See page 5-74)
- Nondestructive testing and visual (see pages 5-74 and 5-75)

(5) Booster Station

- Visual (see pages 5-74 and 5-75)
- Nondestructive (see pages 5-74 and 5-75)
- Manufacturer's inspection schedule and maintenance (see page 5-74)
- Control room monitors, alarms, shutoff (see page 5-74)

A recommended schedule of these inspection methods is given in Table 5-5. These inspection methods and procedures are discussed in the following paragraphs.

TABLE 5-5 RECOMMENDED SCHEDULE FOR INSPECTIONS AND REPLACEMENTS OF OTS COMPONENTS FOR ONSHORE PIPELINE AND APPURTENANCES

OTS COMPONENT	SHIP IN BERTH				PERIODICITY (1)															
	Before	During Off Loading		After	Cont.	Hours		Days	Weeks		Months				Years			Once Per Ship	After	
		Yes	No			2	8	1	1	2	1	2	3	6	1	3	5		Storm	Collision
ONSHORE PIPELINE AND APPURTENANCES (Underground pipeline, above ground pipeline, booster station)								5.2.6.1	(2)	(3)										
				X											5.2.2.4					
	X	X	X	X	5.2.2.5															
				X										5.2.2.6						
		X			5.2.2.7				5.2.2.7		5.2.2.7									
				X	5.2.2.8						5.2.2.8				5.2.2.8					
		X						(4)												
				X											(5)					
	X	X	X	X	(6)															
	X	X	X	X	(7)															

(1) For recommended inspection or replacement event, see the Section identified or note below.
(2) Visual inspection of underground pipeline by airplane or helicopter (see pages 5-72 and 5-74).
(3) Visual inspection of underground pipeline by inspectors walking above pipeline (see pages 5-72 and 5-74).
(4) Visual inspection of above ground pipeline (see pages 5-72 and 5-74).
(5) Nondestructive testing and visual inspection of above ground pipeline (see pages 5-72, 5-74, 5-75).
(6) Manufacturers inspection schedule and maintenance of booster station (see pages 5-72 and 5-74).
(7) Control room monitors, alarms, shutoff of booster station (see pages 5-72 and 5-74).

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Inspections of the underground pipeline are of the same importance as those of the undersea pipeline and for the same reasons. Hence, most of the recommended inspection methods and procedures (and corresponding discussion) are the same as for the undersea pipeline and will not be repeated here. (Inspections for the undersea pipeline are described in Section 5.2.2). The only exceptions to the recommended inspections are that diver inspections are obviously not required and that weekly visual inspections from a helicopter or aircraft are recommended instead of Sonar (sidescan and penetrating), hydrocarbon probe and mapping. It is expected that weekly inspection of the ground above the pipelines can be carried out by helicopter operating personnel who will be normally traveling from the onshore terminal to the platform for routine duties (shuttle personnel, equipment and supply deliveries, etc.) and hence will be of low cost. Visual inspections by an inspector walking above the pipeline is recommended on a bi-weekly basis.

Oil spill risks for the OTS components of the aboveground pipeline and appurtenances, including the booster pump station, are extremely low (less than a barrel a year) for well equipped and well-maintained facilities. Hence inspection methods currently in use are recommended. These include:

(1) Daily visual inspections;
(2) Strict adherence to manufacturer's inspection schedules and maintenance recommendations of booster station OTS components;
(3) Control room monitoring, alarms, and shutoff of all valves, machinery, and other equipment that, if not operating properly or in the incorrect operational mode, can cause an oil spill incident;
(4) Yearly NDT and visual inspections.

Annual inspections by teams are recommended for the aboveground piping and booster station OTS components. Inspection should include visual and NDT methods. The main NDT methods includes ultrasonic radiography (X-ray, gamma-ray, backscatter gamma-ray, where appropriate) and magnetic particle inspection of all piping and vessels. Either ultrasonic, radiographic and magnetic particle inspections should also be used, where appropriate, on manifolds, block valves,

strainers, check valves, flanges, etc. Annual inspections should be carried out at specified, referenced locations (typically about 5000) for the above OTS components. Ultrasonics and magnetic particle should be used for most inspections because of their low cost. Radiographic inspections should be carried out in areas where other methods are difficult to apply. Also, additional areas should be inspected each year using quick, simple inspections such as liquid penetrants.

5.2.7 Onshore Storage Terminal

Oil spill risks are negligible (<0.1 barrel per year) for the OTS components of the onshore storage facilities. As noted previously, this is due to the secondary containment system, a retaining dike around the onshore terminal, that greatly limits the possibility of escape of oil outside the facility. Hence, the only inspections that are necessary and are recommended are daily visual inspection of the drainage control system (this includes the retaining dikes and the drain valve from the dike) and a continuous control monitor on the valve. Manufacturer's suggested maintenance and inspection of the control system and drain valve operation is also recommended.

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5.3 RECOMMENDATIONS FOR DEVELOPMENT OF IMPROVED INSPECTION TECHNIQUES

Inspection methods and procedures recommended for further development include the following:

(1) Hose and String

- Acoustic array (see Section 5.3.1.1)
- Oil spill detector on ship (see Section 5.3.1.2)
- OTS control system, approximately 1 percent accuracy (pressure, flow, etc.) installed on ship, SPM, PLEM and pumping platform (see Section 5.3.1.3)
- Optical borehole (with hose string evacuation) (see Section 5.3.1.5);

(2) Mooring System

- Acoustic array (see Section 5.3.1.4);

(3) Piepline

- Pipeline inspection pig with low-light TV (development of TV transmission techniques only) (see Section 5.3.2.2.b)
- Pipeline inspection pig with ultrasonic imaging (development applies only to modification for use on 54-inch pipelines) (see Section 5.3.2.2.a)
- Acoustic Array (see Section 5.3.2.1).

The recommended schedule of these inspections was presented in Tables 5-1 and 5-2. Inspection methods and procedures utilizing these techniques are described in detail in the following paragraphs.

The acoustic array system (Section 5.3.1.1), if developed, is highly cost-effective (less than $1K per barrel saved) for detecting leaks and incipient failures in the hose string. This is the only inspection method that could provide effective and continuous detection during offloading in darkness and bad weather. In addition, this inspection method can be used when not offloading. Implementation of the acoustic array system, together with the recommended methods described previously, is expected to further improve both the reliability and the effectiveness (relative risk of oil spilled reduced from 900 to 500 bbls). Finally, the acoustic array system, if developed to its fullest potential, could reduce the extent of the recommended continuous visual inspections and could extend the operating life of the hose string. The acoustic array system requires low developmental costs.

Continuous monitoring with an oil spill detector on the deck of the VLCC (see Section 5.3.1.2) would provide improved visual inspection, particularly during the nighttime. The development of such a detector should satisfy a number of requirements: portability, light-weight, separate power supplies, safe and explosion proof, compensation for the draft of the ship during offloading, discrimination between thin and thick oil spill, ruggedness, reliability, and operational simplicity. It is expected that the development cost of this inspection device would be relatively low. Commercial detectors are available that satisfy many of the noted requirements, and these could be engineered for deepwater port use.

A moderately accurate OTS control system (see Section 5.3.1.3) that continuously monitors flow (pressure, flow rate, etc.) during offloading at optimal locations between the ship, SPM, PLEM and the pumping platform also is recommended. If the hose string is monitored at optimum locations, this inspection method provides immediate rupture detection and, also, some detection of incipient failures. The method is recommended principally as a secondary continuous monitoring system for added reliability. It can be used also for alternate or backup inspections, particularly at night or in rough weather.

The final recommended method for the hose string is optical borehole inspection (see Section 5.3.1.5) that is carried out periodically when the ship is not moored to the buoy. The method potentially can provide good incipient failure detection for defects located inside the hose string. None of the current inspections methods recommended in Section 5.2.1 is effective in this location. The inspection requires that the hose string be evacuated, and that the interior of the hose be inspected by a fiber optics viewing device with a light source. Damage such as blisters, bulges, separation of the tube from the carcass, tears, cuts, etc. can be detected. Practical factors, such as the effects of hose string movement or configuration during inspection, may limit the effectiveness of the method. Also, implementation costs may limit inspections to the hose sections most likely to fail. However, considering that vacuum inspections are one of the main type of inspections now carried out onshore to determine that the hose is suitable for reuse, it appears worthwhile to develop this method for inspection of the installed hose string.

The acoustic inspection system (see Section 5.3.1.4) is recommended for detection of incipient failures and ship breakout from the mooring system. This method (see discussion in Section 4.4.2.1), can be used as a secondary continuously monitoring system to provide added reliability when used with the recommended mooring load monitoring system. Moreover, the method can provide more effective detection of incipient failures than the mooring load monitoring system. Development costs, however, are expected to be higher, much higher, for example, than the acoustic array system for the hose string. This is due to two main reasons. First, very limited experimental acoustic emission data are available for this specific application. Secondly, an extensive experimental testing program would have to be carried out to produce a reliable system.

Development of TV transmission, without the use of a coaxial cable, is recommended for TV inspection pig (see Section 5.3.2.2.a). Only minimal development costs are expected. TV inspection pigs* are commercially available; however, they must be pulled or pushed through the pipelines in lengths of less than 10,000 feet because of the necessary TV transmission cable. The only major problem that must be solved is the development of a method to transmit the camera signal back to the control room without a cable, while the pig is moving through the pipeline. A pipeline inspection pig with low-light TV would be highly effective primarily in improving the reliability of incipient failure inspections that use other types of inspection pigs for internal pipeline inspections. For example, detection of defective welds, crack severity, etc. currently require skilled interpretation of the analog voltage data records from a magnetic flux inspection pig. In many instances, the severity and location (inside or outside of the pipe wall) of these defects may be uncertain. A visual examination of the particular area in question would help in evaluating the possible defects. The low-light TV inspection pig would be either a part of the magnetic flux inspection pig or used immediately after the latter.

The ultrasonic imaging (3-dimensional data) inspection pig (see Section 5.3.2.2.b), that is propelled through the pipeline by fluid

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* Existing TV inspection pigs would be suitable for SPM pipeline or the hose string.

flow, should provide excellent pipeline incipient failure detection. It potentially is much superior to any inspection pig currently known. However, the cost of development of the ultrasonic imaging pig is expected to be extremely high (several millions of dollars). The development costs are not justified for deepwater port applications because the effectiveness of this device (see Section 4.4.4) is only a relative risk reduction of about 250 barrels of oil spilled and a cost-effectiveness only slightly better than existing inspection pigs. However, if this inspection device is developed by other means and proves to be reliable and cost-effective, it is recommended that its adaptation for use in large diameter, 54-inch pipelines be carried out. It should be noted, however, that the development of similar, but less sophisticated inspection pigs which use passive acoustics and active ultrasonics, has incurred numerous difficulties over the last 10 years. These inspection pigs currently are not used except at a few isolated locations. Hence, successful development of a reliable ultrasonic imaging inspection pig may not be likely in the immediate future.

A continuous monitoring acoustic array (see Section 5.3.2.1) for pipeline inspections currently is being evaluated in a study for the Environmental Protection Agency under Contract 68-03-2532. Although the method appears to provide good detection of incipient failures and is cost-effectiveness, further development is not recommended until this EPA study is completed.

5.3.1.1 Acoustic Array on Hose String

OTS Component
Hose string

Periodicity
Continuous

Inspection Method and Procedures
Acoustic array system, mounted on hose string, continuously monitors and locates leaks and provides incipient failure detection

Special Equipment
Acoustic array system with buoy alarm, recorder, ship alarm and continuous computer monitoring on platform

Safety Precautions
No special precautions, except for observing standards regarding electrical equipment in flammable atmospheres

Inspections

(1) Hose String

Hose string

a. Leakage
b. Internal and external damage
c. Incipient detection and also location of hose string damage
d. Impact detection and location

5.3.1.2 Oil Spill Detector on Ship

OTS Component
Hose string

Periodicity
Continuous while ship in berth

Inspection Method and Procedure
Oil spill detector mounted at bow of ship

Special Equipment
Oil spill detector with alarm, that discriminated between a sheen and thick slick of oil, covers a broad area and compensates for draft of ship

Safety Precautions
Oil spill detector must meet all safety regulations for shipboard use, including standards for electrical equipment in flammable atmospheres

Inspections

(1) Hose String

Hose string

a. Leakage

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5.3.1.3 OTS Control System 1 Percent Accuracy (pressure, Flow, Volume)

OTS Component

Hose string

Periodicity

Continuous

Inspection Method and Procedure

OTS monitoring (≈1% accuracy) of pressure, flow, volume of oil in hose string for immediate detection of rupture

Special Equipment

OTS Monitoring system with sensors installed at optimum locations between the ship, SPM and platform

Alarms at buoy, ship, and platform

Safety Precautions

No special precautions

Inspections

(1) Hose String

Hose string

a. Rupture
b. Some incipient failure detection via interpertation of unusual fluctuation in recorded flow variables

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5.3.1.4 Acoustic Array for Mooring System

OTS Component
Mooring system

Periodicity
Continuous while ship in berth

Inspection Method and Procedures
Acoustic array monitoring system for acoustic emissions from mooring system loadings

Special Equipment
Accoustic array system for monitoring acoustic emissions and buoy alarm and recorder, ship alarm, and continuous computer monitoring and alarm at platform control

Safety Precautions
No special precautions

Inspections

(1) Mooring system

Mooring system

a. Excessive loading
b. Hawser damage
c. Location of hawser damage and defects
d. History of acoustic emissions from mooring system

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5.3.1.5 Optical Borehole for Hose String

OTS Components
Floating hose string, submarine hose string

Periodicity
2 months

Inspection Method and Procedures
Optical borehole - visual inspection of inside of hose string while under vacuum using flexible device with light source to inspect inside of hose

Special Equipment
Evacuate hose, drain, hose section, borehole adaptors on every other hose flange, and optical borehole devices.

Safety Precautions
Tanker not to be moored to buoy
Diving regulations to be observed

Inspections

(1) Hose String

Floating hoses and submarine hoses

a. Visually inspect for separation in liner
b. Visually inspect for bubbles in liner
c. Other damage
   - blisters
   - tears
   - cuts
   - gouges
   - miscellaneous defects

NOTE: 1. Because of hose movement, the value of this inspection method is uncertain. Also the reliability, sensitivity, and practical problems of inspection are not known. This method must be tested on installed hose strings at DWP's. Method may be suitable for hose sections most likely to fail (i.e., first hose off CALM SPM, hose that breaks water, etc.)

2. Inspections should be carried out during scheduled hose string visual and NDT inspections.

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5.3.2.2a Pipeline Inspection Pig - Ultrasonic Imaging (3-dimensional data) Pipeline

OTS Component

Undersea and underground pipelines

Periodicity

Every six months

Inspection Method and Procedures

- Ultrasonic imaging inspection pig (3-dimensional data) propelled through piepline by fluid flow
- Inspection should be carried out after pipeline is cleaned by a good, high quality cleaning pig
- Inspection should be scheduled when pipeline is normally out of service to minimize cost
- Inspections should be carried out by a qualified inspection service

Special Equipment

Pig sending and receiving trap, pressure and flow monitoring, locator device on inspection pig

Safety Precautions

No special precautions

Inspections

(1) Pipeline (defects located in 3-dimensions)

a. Defects inside pipeline wall
b. Girth welds
c. Corrosion
d. Loss of material on inside or outside of wall
e. Wall thickness
f. Cracks
g. Gouges
h. Wrinkles
i. Hydrogen blisters
j. Improper bends
k. Hard spots, flat spots
l. Pipeline bare surface
m. Soil level around pipeline

NOTE: 1. This inspection is also recommended before pipeline becomes operational for background and reference data.

5.3.2.2b Pipeline Inspection Pig with Low-light TV Inspection Camera

OTS Component
Undersea or underground pipeline

Periodicity
Every six months

Inspection Method and Procedures

- TV inspection camera pig propelled through pipeline by fluid flow
- Inspection should be carried out after pipeline is cleaned by a good high quality cleaning pig
- Inspection should be scheduled immediately after inspection by magnetic flux-type inspection pig for improved reliability of inspection data by the combined inspection results
- Inspection should be carried out by a qualified inspection service
- Pipeline should be filled with water--preferably clear, clean water

Special Equipment
Pig sending and receiving traps, pressure and flow monitoring, location device on inspection pig

Inspection

(1) Pipeline

a. Slightly better than visual inspection

- cracks
- pits
- weld defects
- loss of material on inside of pipe wall
- partially closed valves or valve damage
- dents
- flat spots
- gouges
- wrinkles
- hydrogen blisters

NOTE: 1. This inspection is recommended before pipeline becomes operational for background or reference data.

2. Required development of a technique to transmit TV signals without cable attached to pipeline (See References 30 and 49 for solution of a similar problem but in a low frequency range).

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7.0 GLOSSARY

CALM (Catenary Anchor Leg Mooring): A single point mooring which is anchored to the sea bed by multiple anchor chains, usually six in number.

DWP (Deepwater Port): An offshore facility for mooring VLCCs and transferring oil between an onshore storage facility and the VLCC.

DWT (Deadweight Tons): Total carrying capacity of cargo, bunkers, stores and crew; approximately equal to the cargo carrying capacity of a tankship.

Fluid Swivel: A component of a SPM which permits rotation of the hose strings about a fixed point.

Hose String: The assemblage of individual sections of hose (floating or submarine) for transferring oil between the tanker and the SPM.

LOOP: A deepwater port oil transfer terminal complex proposed for installation off the coast of Louisiana.

Monobuoy: The floating component of a SPM.

OCIMF (Oil Companies International Marine Forum): An industry organization for sharing data and information concerning marine problems and for setting standards for marine equipment.

OTS (Oil Transfer System): The system of a DWP for transferring oil, including the hose strings, the SPM, undersea pipelines, pumping platform and onshore pipelines connecting to a storage facility.

PDU (Product Distribution Unit): A fluid swivel which can transfer more than one oil product.

PLEM (Pipe Line End Manifold): The manifold at the end of the undersea pipeline which connects to a SPM.

SALM (Single Anchor Leg Mooring): A single point mooring which is anchored through a single anchor leg or chain made fast to a fixed base located on the ocean floor.

SEADOCK: A deepwater port oil transfer terminal complex proposed for installation off the coast of Texas.

SPM (Single Point Mooring): A generic term which includes all floating buoy mooring systems which permit a ship to rotate freely around them.

Tail Hose: That segment of a hose string which is connected to the ship's manifold. It normally is smaller in diameter, lighter and more flexible than the remainder of the hose string.

VLCC (Very Large Crude Carrier): A tanker with a capacity of approximately 180 to 400,000 deadweight tons.

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250A

APPENDIX A

MANUFACTURERS AND INSPECTION COMPANIES SURVEYED

A. MANUFACTURERS AND INSPECTION COMPANIES SURVEYED

The purpose of this appendix is to identify the surveyed companies and to provide a reference source of companies which manufacture the kind of inspection equipment or provide the inspection services which were discussed previously and will be discussed in Appendix B. Nine major inspection areas and five product lines are identified in a legend and then noted, when applicable, for each company surveyed. It is intended that this listing give the user a source for obtaining specific information on the various inspection methods and procedures. The survey is limited based on information available within the scope and frame of this project, and does not include all companies that provide the inspection methods and services discussed. The listing of a particular company is not a recommendation or a solicitation to buy from said company.

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MANUFACTURERS AND INSPECTION COMPANIES SURVEYED

LEGEND

INSPECTION AREAS

1.0 VISUAL
1.1 Diver, submersible
1.2 Optical borehole
1.3 TV monitor
1.4 Tape detection

2.0 OIL SPILL DETECTOR
2.1 On launch
2.2 On ship
2.3 On platform
2.4 On buoy
2.5 Buoy type

3.0 DYNAMIC INSPECTION INTO OTS
3.1 Dye tracing
3.2 Inspection pigs
3.3 Hydrostatic
3.4 Pressure crack wave
3.5 Vacuum
3.6 External hydrostatic

4.0 CORROSION
4.1 Flow sampling
4.2 Corrosion sensors
4.3 Cathodic protection

5.0 NON-DESTRUCTIVE TESTING
5.1 Passive ultrasonics
5.2 Active ultrasonics
5.3 X-ray
5.4 Radioactive isotope, gamma ray
5.5 Magnetic particle
5.6 Magnetic rubber
5.7 Magnetic foil or magnetic tape
5.8 Ultrasonic imaging
5.9 Eddy current
5.10 Penetrants

6.0 SURVEY
6.1 Sonar (bare-surface, overburden)
6.2 Surveying (component location, mapping)
6.3 Sonar

7.0 OTS CONTROL
7.1 Pressure, volume, flow
7.2 Mathematical modeling

8.0 SPECIAL METHODS
8.1 Passive acoustic array-leaks
8.2 Passive acoustic array-acoustic emission
8.3 Passive acoustic-machinery vibration
8.4 Strain-gaged load sensor, mooring load monitor
8.5 Continuous thermistor
8.6 Laser detection-underwater
8.7 Shroud with EMP pulsed coaxial cable
8.8 Double walled pipe
8.9 Double walled hose
8.10 External load (i.e., pulling by ship)
8.11 Seal leak detector
8.12 Liquid level sensor

9.0 MISCELLANEOUS

PRODUCT LINE

A. Inspection transducers or detectors
B. Inspection transducers or detectors with instrumentation
C. Complete inspection systems
D. Inspection services
E. Custom design

MANUFACTURERS AND INSPECTION COMPANIES SURVEYED - LISTING

Aanderaa Instruments Lt. 560 Alpha Street Victoria, B.C. Canada V8Z1B2	
A.B. Plumbing, Heating and Cooling 205-22nd Street Sacramento, CA 95816	3.2 A, B, C, D, E
Acco, Bristor Div. 40 Bristor St. Waterbury, Conn. 06720	
Ace Pipe Cleaning, Inc. 4000 Truman Rd. Kansas City, MO 64127	
Accusonic Division Ocean Research Equipment P. O. Box 709 Falmouth, Mass. 02541	7.1 A, B, C
ADEC Corporation Irvine, CA 92707	7.1 C, E
Aero Vac Products Industrial Products Division- High Voltage Engineering Corp. P. O. Box 416 South Bedford St. Burlington, Mass 01803	
Air Monitor Corporation P. O. Box 6358 Santa Rosa, CA 95406	9 A, B, C, D
Air Products Box 538 Allentown, PA 18105	
Airco Industrial Gases 575 Mountain Ave. Murray Hill, NJ 07974	
Allison Control New Jersey	8.5 A, B, C, D
Alphs Metrics Winnepeg, Canada	
Alphine Geophysical Assocs. Oak Street Norwoor, New Jersey	6.1, 6.2, 6.3 A, B, C, D
American Instrument Co. 8030 Georgia Ave. Silver Spring, MD 20910	
American Standards Testing Bureau, Inc. 40 Walter St. New York, NY 10004	
Ametek Straza Division 790 Greenfield Drive P. O. Box 666 El Cajon, CA 92022	1.1, 5, 6, 7 A, B, C, D, E
Amtek, Inc. (Pa) Station Square Two, Paoli, PA 19301	
AMF Sea-Link Herdon, VA	6, 8 A, B, C, D
AMF Tuboscope Inc. P. O. Box 808 Houston, TX 77001	3.2, 5 A, B, C, D
Amiproducts, Inc. 1504 W. 28th St. New York, NY 10001	
Analog Technology 3410 E. Foothill Pasadena, CA 91107	
Androx Limited P. O. Box 814 St. Catherine, Ontario	5 A, B, C, D
Andrex Radiation Products Copenhage, Denmark	5 A, B, C, D
Applied Instruments Corp. 1681 West Broadway Anaheim, CA 92802	
Applied Research Labs. P. O. Drawer 1, Homestead, Fla. 33030	5 A, B, C
Aquatech, Inc. 10620 Cedar Ave. Cleveland, Ohio 44106	
AstroNautical Research, Inc. Dunham Road P. O. Box 495 Beverly, Mass. 01915	-
Atomics International 8400 DeSoto Ave. Canoga Park, CA	5 A, B, C, D, E
Automation Industries Sperry Division Downey, CA	5 A, B, C, D
Automation Products, Inc. 3030 Max Roy Houston, TX 77008	

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LISTING - (Continued)

B & K Instruments, Inc. 5.0
5111 West 164th St. A, B, C
Cleveland, Ohio 44142

Bach---ch Instrument Co.
West ---st Operations
2300 Leghorn St.
Mt. View, CA 94043

Badger Meter, Inc. 7.1
Environmental & Electronic A, B, C
Products Division
150 E. Standard Ave.
Richmond, CA 94804

Bailey Meter Company,
Sub Babcock & Wilcox Co.
29801 Euclid Ave.
Wicklittle, Ohio 44092

Baird-Atomic, Inc. 2.2, 2.3
125 Middlesex Turnpike A, B, C, D
Bedford, Massachusetts 01730

Barnes Engineering
Stanford, CT

Barry Research Corporation
1530 Page Mill Road
Palo Alto, CA 94304

Barton 7.1
Monterey Park, CA A, B

Beck Instruments
2500 Harbor Blvd
Fullerton, CA

BBN Instrument Corp. 5
Cambridge, Mass A, B, C

Belco Pollution Control
Corporation
570 W. Mt. Pleasant Ave.
Livingston, NH 07039

Belfort Instrument
1605 S. Clinton
Baltimore, Maryland

Bendix
Environmental Science Div.
1400 Taylor Avenue
Baltimore, Maryland 21204

Bendix Corporation
New York, NY

Benthos, Inc. 5, 6
North Falmouth, Mass 02556 A, B, C, D

Bethany International, Inc. 7.2
6161 Savoy Drive C, E
Suite 940
Houston, TX 77036

The Bethlehem Corporation 7
25th and Lennox Streest A, B
P. O. Box 348
Easton, PA 18042

The Bethlehem Corporation
225 W. 2nd St.
Bethlehem, PA 18016

Block Engineering
Cambridge, Mass

Blue White Industries
14931 Chestnut St.
Westminster, CA 92683

Brantner and Assoc., Inc.
P. O. Box 2224
Newport Beach, CA 92663

Bridgestone Tire Company, Ltd.
Yokohama, Japan

British Hovercraft Corp.
East Cowes
Isle of wright, England

Branson Probolog 3.2
A, B, C, D

Brooks Instrument,
Div. of Emerson Electric
407 W. Vine St.
Harfield, PA 19440

Bunker Ramo
Electronic System Div.
Westlake, CA 91354

BVS. Inc.
Water Pollution Samplers
P. O. Box 243
Hone Brook, PA 19344

B/W Controls, Inc.
2200 East Maple Road
Birmingham, Michigan 48102

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LISTING - (Continued)

Cambridge Filter Corp.
7645 Henry Clay Blvd.
Syracuse, NY 13201

Cameron Ironworks
Houston, TX

Can-Tex Industries,
Div. of Harsco Corp
P. O. Box 340
Mineral Wells, TX 76067

Capital Controls Company
Division of Dart Industries
Advance Lane
Colmar, PA 18915

Capital Controls Company
Division of Dart Industries
P. O. Box 211
Colmar, PA 18915

The Carborundum Company
Process Equipment Plant
Aurora Road
Solon, Ohio 44139

The Carborundum Company
Graphite Products Div.
P. O. Box 577
Niagra Falls, N.Y. 14302

C-E INVALCO,
Div. of Combustion Engineering
P. O. Box 556
Tulsa, OK 74101

Central States Underwater Contracting, Inc. 4, 5, 6 D
3077 Merriam Lane
Kansas City, KS 66102

Century Systems Corp.
P. O. Box 133
Arkansas City, KS 67005

Cherne Industrial, Inc. 3.2, 8.11
5701 South Country Road 18 A, B, C, D. E
Edina, Minnesota 55436

Chemtrix
Hillsboro, OR

Circle Chemical Co. 5.6
P. O. Box 221 A
Hinckley, IL 60520

Circle Seal Corporation 9
P. O. Box 3666 A
Anaheim, CA 92803

Cleveland Controls, Inc.
1111 Brookpark Rd.
Cleveland, Ohio 44109

Columbia Research Lab 5
Woodlyn, PA A, B, C

Commercial Diving Division
3323 W. Warner Ave.
Santa Ana, CA

Consolidated Controls Corp.
15 Durant Ave.
Bethel, Conn 06801

Consolidated Technology
P. O. Box 261
Mt. Kisco, NY 10549

Controlotron Corp
111 Bell St.
W. Babylon, NY 11704

Corning Glass Works,
Houghton Pk
Corning, NY 14830

Cox Instrument 7
15300 Fullerton, A, B
Detroit, Mich. 48227

CUES, Inc.
3501 Vineland Rd.
P. O. Box 5516
Orlando, FL 32805

C. W. Stevens, Inc.
429 S. Walnut St.
Kennett Square, PA 19348

LISTING - (Continued)

Daniel Industries P. O. Box 19097 Houston, TX 77024	7.1 A, B, C, D	
Data Courier, Inc. 620 So. Fifth St. Louisville, Kentucky 40202		
Datemetrics, Inc. 340 Fordham Rd. Wilmington, Mass. 01887		
Dayton X-ray Co. 1150 W. Second St. Dayton, Ohio	5 A, B, C, D	
Del Norte Technology, Inc. P. O. Box 696 Euless, Texas 76039	4, 5, 6 A, B, C, D, E	
Det Norske Veritas Gren Seveien 92 Oslo 6, Norway	4, 5, 6 A, B, C, D	
Detroit Testing Lab., Inc. 8720 Northend Avenue Oak Park, Michigan 48237	5 A, B, C, D	
Device Engineering, Inc. 36 Pier La., W. Fairfield, NJ 07006		
Dieterich Standard Corp. Subsidiary of Doover Corp. Box 9000 Boulder, Colorado 80302		
Dow Chemical Pasadena, Calif	4.3	
Dranetz Engineering Labs 2385 S. Clinton Ave. South Plainfield, NJ 07080		
Dresser Industries, Inc. 10201 Westheimer Road P. O. Box 2928 Houston, TX 77001		
Duriron Company, Inc. Dayton, Ohio 45401	4.3 A, B, C, D	
DuPont Co. Instrument Products Scientific and Process Div. Wilmington, Del. 19898	7.1 A, B, C	
D. W. Harmon Company 5353 Topanga Cyn Blvd Ste 3 Woodlands Hills, CA 91364		
Dwyer Instruments, Inc. P. O. Box 373 Junction Ind. 212 and U.S. 12 Michigan City, Indiana 46360		
Dynamold, Inc. P. O. Box 9616 2905 Shamrock Ave. Fort Worth, TX 76107	5.6 A, B, C	

LISTING - (Continued)

Echo Laboratories 5.2
Titusville, PA 16354 A

Ecologic Instruments
Bohemia NY

Ecosystem Research and
Technology Corp.
P. O. Box 35712
Dallas, EX 75235

E. D. Bullard Co. 9
2680 Bridgeway A, B, C
Sausalito, CA 94965

Edo Western Corp. 1.2, 7.1
2645 South 300 West A, B, C
Salt Lake City, Utah 84115

E.I. du Pont de Nemours & Co,
Market St.
Wilmington DEL 19898

Electro
15146 Downey Ave.
Paramount, CA 90723

Electro Optics
Santa Barbara, CA

Electric System Design 4.2
317 W. University Dr. A, B, C
Arlington Heights, Ill.

Ellis & Ford Mfg. Co., Inc.
P. O. Box 308
Birmingham, Mich 38012

Endevco 5
Rancho Viejo Rd A, B, C, D
San Juan Capistrano, CA

Engelhard Minerals & 4.3
Chemicals Corp. A, B, C, D
Engelhard Industries Div.
430 Mountain Ave.
Murray Hill, NH 07974

Enraf 8.12
A, B

Environmental Devices Corp.
Tower Building
Marion, Mass. 02738

Environmental Tectronics Corp.
County Line Industrial Park
Southhampton, PA 18966

Envirotech
12881 Knott Ave. Ste 106
Garden Grove, CA 92645

Envirotech Corp.
3000 Sand Hill Rd.
Menlo Park, CA 94025

Eocom
19722 Jamboree Blvd.
Irvine, CA 92715

Epic, Inc. 7.1
Instruments for Science and A, B
Industry
150 Nassau St.
New York, NY 10038

Erdco Engineering Corp.
136 Official Rd.
Addison, IL 60101

ERM/Marathon 7.1
West Germany A, B, C, E
Rep. Proprietary Rights
Service Corp.
180 East End Ave.
New York, NY 10028

Esterline Angus Inst. Corp.
Box 24000
Indianapolis, IN 46224

Exon Nuclear Company, Inc. 5
Research and Technology Center A, B, C, D, E
2955 George Washington Way
Richland, Washington 99352

Extranuclear Labs, Inc.
250 Alphs Dr.
P. O. Box 11512
Pittsburgh, PA 15238

Exotech, Inc.
Garthersburg, Md

259

Fisher and Porter
County Line Rd.
Warminster, Pennsylvania 18974
7.1
A, B, C

FluiDynamic Devices Limited
3216 Lenworth Dr.
Mississauga Ontario
Canada L4X2G1
7.1
A, B, C

Flow Technology, Inc.
4250 East Broadway Road
Post Office Box 21346
Phoenix Arizona 85040
7.1
A, B, C

Formulabs, Inc.,
Flourescent Dye Tracing Systems Div.
529 W. 4th Ave
P. O. Box 1056
Escondido, Calif 92025
(714) 741-2345
3.1

The Foxboro Co.,
Neponset Ave.
Foxboro, Mass 02035
(617) 543-8750
7.1
A, B, C

Foxboro/Trans-Sonics, Inc.
P. O. Box 435
Burling, Mass 01803
7.1
A, B, C

GARD, Inc.
7449 North Natchez Ave
Niles, IL 60648
5.7
A, B, C, D, E

Garret-Callahan Co
111 Rollins Rd
Millbrae, CA 94030

General Dynamics
Electronics Division
San Diego, CA
6
A, B, C

General Electric Company
Ocean Systems Programs Dept.
3198 Chestnut St.
Philadelphia, PA 19101

General Metal Works, Inc.
8368 Bridgetown Road
Cleves, Ohio 45002

General Monitors, Inc.
3019 Enterprise St.
Costa Mesa, CA 92626

General Oceanics, Inc.
5535 N.W. 7th Ave
Miami, Fla. 33127

GI
Box 3356
Cherry Hill, NJ 08034

G&H Laboratories
1001 W. Arbor Vitae
Inglewood, CA 90301

Gianni Institute
Indio, CA
5.6, 9
A, B, C, D, E

Girard Polly-Pig Inc.
P. O. Box 27208
Houston, TX 77027
3.2
A, B, C, D

Glass Innovations, Inc.
P. O. Box B
Addison, NY 14801

Gould, Inc. Control and
System Division
340 Fordham Rd
Wilmington, Mass. 01887
7.1
A, B, C

Gow-Mac Instrument Co.
100 Kings Road
Madison, NJ 07940

G.M. Mfg & In[illegible]trument Corp.
P. O. Box 94[illegible]
El Cajon, CA [illegible]2022

Gulton Industries, Inc.
Servonic/Instrumentation Div.
1644 Whittier Ave.
Costa Mesa, CA 92627

Gulion Industries
Fullerton, CA 92651
5.7
A, B

A-8

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LISTING - (Continued)

Halliburton Services A Division of Halliburton Co. Duncan, Oklahoma 73533	
Harris Calorific Division Emerson Electric Co. 5501 Cass Avenue Cleveland, Ohio 44102	
Hastings Hampton, VA	7 A
The H.C. Nutting Co 4120 Airport Road Cincinnati, Ohio 45226	
Healy Scott Int. San Diego, CA	3.2 A, B, C, D
Heath Consultants, Inc. 100 Tosca Drive Stroughton, Mass. 02072	3.2 A, B, C, D
Helle Engineering, Inc. 7198 Convoy Court San Diego, CA 92120	5, 6
Hershey Products, Inc. Niagara, NY	7 A, B
Hershey Products, Inc. Industrial Measurement Div. Old Valley Falls Rd Spartanburg, SC 29303	
Hewlett Packard Delcon Division	5.1, 8.3 A, B, C
H. C. Nutting Co. Cincinatti, Ohio	5 A, B, C, D
High Voltage Engineering Corp. S. Bedford Rd. Burlington, Mass 01803	
Holiday Carporinta, Calif	4.2 A, B
Holosonics, Inc. 2400 Stevens Drive Richland, Wash. 99352	3.2, 5.2, 5.8 A, B, C, D, E
Honeywell, Inc. 1100 Virginia Drive Fort Washington, PA 19034	
Honeywell, Inc. Lexington, MA	
Honeywell, Inc. Marine Systems Division 5303 Shilshole Ave. N.W. Seattle, Washington 98107	
HRB Singer State College, PA	
Humphrey, Inc.	6 A
Hydro Products A. Tetra Tech Company 11777 Sorrento Valley Road San Diego, CA 92121	5 A, B, C

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LISTING - (Continued)

IMODCO International, Ltd. Los Angeles, CA	
Impulsphysics Hamburg, Germany	
Innerspace Technology, Inc. 27 Frederick Street Waldwick, NJ 07463	
Inertia Switch, Ltd. Banchory Works Hardings Lane Hartley Wintney Hants, United Kingdom Hartley Wintney-2951	
Institute for Research, Inc. 8330 Westglen Dr. Houston, TX 77063	
Instron Corp. Los Alamitos, CA	5 A, B, C
Internation Imaging Systems Commack, NY	
Internation Sensor Technology 3201 South Halladay Street Santa Ana, CA 92705	
International Transducer Corp. Subsidiary of Channel Ind., Inc. 640 McCloskey Pl. Goleta, CA 93017	5 A, B, C
InterOcean Systems, Inc. 3540 Aero Ct. San Diego, CA 92123	
InterOcean Systems, Inc. 3510 Kurtz Ave San Diego, CA	9.1 A, B, C, D
Intersea Research Corp. P. O. Box 2389 La Jolla, CA 92038	1.1, 5 A, B, C
Ionics, Inc. 65 Grove Street Watertown, Mass 02172	
IRD Mechanalysis, Inc. Columbus, Ohio	8.3 A, B, C, D
ISCO P. O. Box 5347 4700 Superior Ave Lincoln, Neb. 68505	
ITT Barton 580 Monterey Pass Rd. Monterey Park, CA 91754	
James Dean Divers, Inc. New Orleans, LA	4, 5, 6 D
John Chance Company LaFayette, LA	4, 5, 6 D
J. Ray M'Dermott	
SBM, Inc. New Orleans, LA	4, 5, 6 D
Kahl Scientific Instrument Corp P. O. Box 1166 El Cajon, CA 92002	
Kawaski Intl. P. O. Box 1082 Cupertino, CA 95014	5 A, B
KB Heroteck P. O. Box 350 Lewistown, PA 17044	5 A, B
K.J. Law 23660 Research Drive Farmington Hill, Mich.	5.9 A, B, C
Klein Associates Undersea Search and Survey Salem, New Hampshire 03709	6.1, 6.2, 6.3 A, B, C, D, E
Konel Grp. Corporation Subsidiary Narco Scientific 271 Harbor Way, S. San Francisco, CA 94080	
Kontes, Spruce St. Vineland, NJ 08360	
Kratos 403 S. Raymond, Pasadena, CA	
Kurz Instruments, Inc. P. O. Box 849 20 Village Square Carmel, CA 93924	
KZF Environmental Design Cons., Inc. 2830 Victory Pkwy Cincinnati, Ohio 45206	

LISTING - (Continued)

Land and Offshore Services
Banchory Grampian, Scotland

Lear Siegler, Inc.
Environmental Technology Div
74 Inverness Drive East
Englewood, Colo. 80110

Leeds & Northrup Co.
Sumneytown Pike
North Wales, PA 19454

Lenox Instrument
An Esterline Company
111 East Luray Street
Philadelphia, PA 19120

Leopold Company
Division of Sybron Corp.
227 S. Division Street
Zelienople, PA 16063

Lester Laboratories, Inc.
2370 Lawrence St.
Atlanta, GA 30344

Leupold & Stevens, Inc.
600 N.W. Meadow Dr.
P. O. Box 688
Beaverton, Ore. 97005

Lion Precision Corp.
60 Bridge St.
Newton, Mass. 02195

Lordkinematics
Paramous, NH

Lumenite Electronic Corp.
2331 N. 17th Ave.
Franklin Park, IL 60131

Mackallor Bros. Chino, CA	3.2 A, B, C, D, E
Magnaflux Corporation 7300 West Lawrence Avenue Chicago, IL 60656	5,6 A, B, C, D

Magnavox
Govt. and Indust.
Electronics Co.
2829 Maricopa Street
Torrance, CA 90503

Menning Environmental Corp. 120 DuBois Santa Cruz, CA 95061	6 A, B, C, D

Manostat Corporation
519 Eigth Ave
New York, NY 10018

Mapco, Inc. 1800 South Baltimore Ave. Tulsa, Oklahoma 74119	7.1 A, B, C, D

The Marconi International
Marine, Ltd.
Oil Industry Division
Elettra House, Westway
Chelmsford, Esses, England

Marine Moisture Control Co. 449 Sheridan Blvd. Inwood, L.I., NY 11696	6 A, B, C, D

Martek Instruments
Newport Beach, CA

Matheson P. O. Box 85 East Rutherford, NJ 07073	7.1, 7.2 A, B
McDonnell Douglas Corp. Huntington Beach, CA	8.0 A, B

Mead Instruments Corp.
One Dey La
Riverdale, NJ 07457

Measurement Control Systems
Division of United Spring
1495 E. Warner Ave.
Santa Ana, CA 92707

Meriam Instrument
10920 Madison Ave.
Cleveland, Ohio 44102

Metrotek, Inc. P. O. Box 101 Richland, WA 99352	5 A, B, C

MG Scientific Gases
210 Cougar Ct
Hillsborough, NJ 08876

Micro Motion, Inc. 2700 29th St Boulder, Colo	7.1 A, B, C

Milton-Roy Co.
Hays-Republic Div
742 E. Eight St.
Michigan City, Ind. 46360

Mine Safety Appliances Co.
400 Penn Center Blvd.
Pittsburgh, PA 15235

Moniter Technology, Inc.
630 Price Avenue
Redwood City, CA 94063

Montedoro-Whitney Corp
2740 McMillan Rd.
P. O. Box 1401
San Luis Obispo, CA 93406

Motorola, Inc. 8201 E. McDowell Rd Scottsdale, Arizona	6 A, B, C, D, E

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Nebraska Testing Labs 4453 S. 67th St. Omaha, Neb 68106	5 D
New York Testing Labs, Inc. 81 Urban Ave. Westbury, LI, NY 11590	5 A, B, C, D
Nippon Kokan Japan	3.2 A, B, C, D
Nupro Co. 4800 E. 345th St. Willoughby, Ohio 44094	
Nu Sonics Inc. Tulsa Oklahoma Phone (203) 623-8800	7.1 A, B, C
National Environmental Instruments, Inc. P. O. Box 590 Pilgrim Station Warwick, RI 02888	
National Instrument Labs, Inc. 910 Princess Ann St. Fredricksburg VA 22401	
National Power Rodding Corp. 1000 S. Western Ave. Chicago, IL 60612	
NB Products, Inc. 935 Horsham Rd. Horsham, PA 19044	
N-CON Systems Co., Inc. 308 Main St. New Rochelle, NY 10801	
Ocean Research Equipment, Inc. P. O. Box 709 Falmouth, Mass. 02541	7.1 A, B
Ocean Systems Houston, TX	
Oceaneering, International Houston, TX	6 A, B, C, D, E
Ocean Technical Services Ltd 43/44 Albermarle St. London W/X 3Fe England	8.4 A, B, C, D, E
Offshore Navigation, Inc. 5723 Jefferson Hwy. Harahan, LA 70183	6.1, 6.2, 6.3 A, B, C, D
Olympus Corp. of America/ Industrial Fiberoptics Dept. 2 Nevada Drive New Hyde Park, NY 11040	1.2 A, B, C
Optronics Labs Silver Springs, MD	
O.R.E., Inc. P. O. Box 709 Falmouth Heights Rd. Falmouth, Mass. 02541	6.1, 6.2 A, B, C, D, E

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LISTING - (Continued)

Panometrics — 5; A, B, C
221 Crescent St.
Waltham, Mass. 02154

Peabody Testing — 5, 5.4; A, B, C, D
Magnaflux Corp.

Pennwalt
Wallace and Tiernan Division
25 Main St.
Belleville, NJ 07109

The Permutit Co., Inc. of
Sybron Corp.
E. 49 Midland Ave.
Paramus, NJ 07652

Perry Oceanographics, Inc. — 1.2, 5, 6; A, B, C, D
P. O. Box 10297
Riviera Beach, Florida 33404

Plessey, Inc. — 6.1, 6.2; A, B, C, D
Tellurometer USA
89 Marcus Blvd.
Hauppage, NY 11787

Joseph G. Pollard Co., Inc. — 5.1; A, B, C, D
New Hyde Park, NY 11040

Power Engineering & Equip. Co.
1826 W. 213 St.
Torrance, CA 90501

Precision Gas Products, Inc.
Sub. of Burdox, Inc.
681 Mill Street
Rahway, NJ 07065

Preformed Line Products
P. O. Box 91129
Cleveland, Ohio 44101

Princeton Applied Research Corp.
P. O. Box 2565
Princeton, NJ 08540

Pro-Tech, Inc.
Liquid Samplers and Flow
Monitors
1510 Russel Rd.
Paoli, PA 19301

Radiation Dynamics, Inc.
Melville, NY

RAMCO
Dallas, TX

Ramapo Instrument Co., Inc. — 7.1; A, B, C
2 Mars Court
P. O. Box 429
Montville, NJ 07045

Rambie, Inc. — 2.1, 2.2, 2.3, 2.4; A, B, C, D, E
P. O. Box 3214
Irving, TX 75061

Raytheon Company — 6.1, 6.2; A, B, C, D
Submarine Signal Div.
Ocean Systems Center
1847 W. Main Road
Portsmouth, RI 02871

Reliance Instrument Mfg. Corp.
164 Garibaldi Ave.
Lodi, NJ 07644

Reynolds French Co. — 5.0

Robertshaw Controls Co.,
Industrial Instrumentation Div.
1809 Staples Mill Rd.
Richmond, VA 23230

Robinson Pipe Cleaning Co.
606 W. Pike St.
Canonsburg, PA 15317

Roma Sales, Inc.
407A North Central Avenue
Glendale, CA 91203

R. P. Cargille Labs, Inc.
55 Commerce Rd
Cedar Grove, NJ 07009

Earl Ruble & Associates, Inc.
217 S. Lake Ave.
Duluth, Minn 55802

LISTING - (Continued)

SBM of America — 8.4
Houston, TX — A, B, C

Schaevitz Engineering — 5
P. O. Box 505 — A, B, C
Camden, NJ 08101

Science Pump Corp.
1431 Ferry Avenue
Camden, NJ 08104

Science Applications, Inc. — 8.1, 8.2, 8.3, 8.7
201 West Dyer Rd. — A, B, C, D, E
Unit 6
Santa Ans, CA

Scientific Gas Products, Inc.
2230 Hamilton Blvd.
S. Plainfield, NJ 07080

Scientific Glass & Inst., Inc.
P. O. Box 6
Houston, TX 77001

Scott Ato
225 Erie Street
Lancaster, NJ 14086

Seatech Corp.
Ocean Engineering
985 N.W. 95th St.
Miami, Fla. 33150

SEDCO
Houston, TX

Sensotec
1400 Holly Avenue
Columbus, Ohio 43212

Siemens Aktiegesellschaft
Bereich Mebund Prozebtechnik
P. O. Box 211080
Federal Republic of Germany

Sierra Instruments, Inc.
P. O. Box 909
Carmel Valley, CA 93924

Sigma Instruments Ltd. — 4.2, 4.3
55 Six Point Road — A, B, C
Toronto, Ontario M8Z 2X3

Sigmamotor, Inc.
14 Elizabeth St.
Middleport, NY 14105

Singer-American Meter Div.
13500 Philmont Ave.
Philadelphis, PA 19116

Sirco Controls Co. — 4, 5, 6
401 Second Ave. W. — D
Seattle, Washington 98119

Sirco Products Limited
8815 Selkirk Street
Vancouver, BC V6P 4J7

Sofec, Inc.
2000 W. Loop
Houston, TX

Soltraplex, Inc.
Lehavre, France

Sona Tech, Inc. — 6
Goleta, CA 93017 — A, B, C, D

Sonic Inc — 5
Trenton, NJ — A, B, C

Sound Wave Systems, Inc.
3001 Red Hill Bldg. 1 Ste 102
Costa Mesa, CA 92626

Spectrogram — 2.5
North Hampton, Conn — A, B, C

Sperry — 6.1, 6.2
Marine Systems — A, B, C, D, E
Greak Neck, NY 11020

Stoner Associates — 7.2

Sub Sea International — 1, 4, 5, 6
New Orleans, LA — D

Sunshine Chemical Corp.
P. O. Box 17041
West Hartford, Conn 06117

Supelco, Inc.
Supelco Park
Bellefonte, PA 16823

Sylvester Underseas Inspection — 1.1, 4, 5, 6
900 Hingham Street — D
Rockland, Mass. 02370

LISTING - (Continued)

TDW Pipeline Surveys P. O. Box 1286 Tulsa, OK 74101	3.2, 5.1 A, B, C, D, E
T.D. Williams, Inc. P. O. Box 3404 Tulsa, OK	3.2 A, B, C, D, E
TechEcology, Inc. 645 N. Mary Sunnyvale, CA 94086	
Teledyne Analytical Instruments P. O. Box 70 333 W. Mission Dr. San Gabriel, CA	4.1, 9 A, B, C
Teledyne Hastings-Raydist P. O. Box 1275 Hampton, VA 23661	
Teledyne Gurley 514 Fulton St. Troy, NY 12181	
Terriss-Consolidated Ind. 126-128 Hope Street Brooklyn, NY 11211	
Texas Instr. Dallas, TX	
Thermal Instrument Co. 217 Sterner Mill Rd Trevose, PA 19047	
Thermal Systems, Inc. 2500 Cleveland Ave. N. St. Paul, Minn 55113	7.1 A, B
Top Flight, Inc. Oklahoma City, OK	
Tom Ponton Industries, Inc. 13923 Artesia Blvd. Cerritos, CA 90701	
Transworld Inspection Corp.	3.2 A, B, C, D
Turner Designs 2247 A Old Middlefield Way Mountain View, CA 94043	
Tylan Corporation 19220 So. Normandie Torrance, CA 90502	
Tuthill Pump Co. 12500 S. Crawford Ave. Chicago, IL 60658	
Uniloc Irving, CA	
Union Carbide Corporation 120 South Riverside Plaza Chicago, IL 60606	4.3 A, B, C
Unit Process Assemblies, Inc.	5.4
UOP Johnson Division P. O. Box 3118 St. Paul, Minn. 55165	
Vanode Company Torrance, CA	4.3
Varec	8.12 A, B
Varian 611 Hansen Way Palo Alto, CA 94303	5.5 A, B, C, D
Varian/Vacuum division 9901 Paramount Blvd. Downey, CA 90240	
Vetco Pipeline Service 1600 Brittmoore road Houston, Texas 77043	3.2, 5.4 A, B, C, D, E
Vidimar Tulsa, OK	3.2 A, B, C, D, E

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LISTING - (Continued)

Wallace-Fisher Instrument Co. P. O. Box 51 Ocean Grove Station Swansea, Mass 02777		
Waukesha Foundry Division Abex Corporation 1300 Lincoln Ave. Waukesha, Wisc. 53186	7.1, 9 A, B, C	
Weather Measure Corporation P. O. Box 41257 Sacramento, CA 95841	9 A, B, C, D	
WECO, Division SMC Brea, CA		
Wesmar Seattle, Washington	6.2 A, B	
Westinghouse Elec. Corp. Oceanic Division (Ultrasonic Flowmeters) P. O. Box 1488 Annapolis, Md	7.1 A, B, C	
Wild Hurburugg Instr. Inc. Famingdale, NY		
Whesssue Fielden	8.12 A, B	
World Wide Oil Too, Inc. 4041 Hollister Houston, TX 77080	3.6 A, B, C, D	
Wright and Wright, Inc. 80 Winchester St. Newton, Mass. 02161	2.1, 2.2, 2.3 A, B, C, D	
Waugh Control Corp. 9001 Full Bright Ave Chatsword, CA 91311	7.1 A, B, C	
Xarway Corporation Blue Bell, PA 19422		
XMAS, Inc. 8186 East 44th Street Tulsa, OK 74145		
Zimmite Corporation 810 Sharon Drive Cleveland, Ohio 44145		
Zurn Industries, Inc. Hays Fluid Controls Div. 12 & Plum Sts. Erie, PA 16512		
Zanderlans and Sons, Inc. 1320 South Socramento St. Lodi, Calif.	8.11 A, B, C, D, E	

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APPENDIX B

INSPECTION METHODS-OPERATION, CAPABILITY, SENSITIVITY, MANUFACTURERS AND COST, ADVANTAGES, DISADVANTAGES AND LIMITATIONS

B. INSPECTION METHODS - OPERATION, CAPABILITY, SENSITIVITY, MANUFACTURER AND COST, ADVANTAGES, DISADVANTAGES AND LIMITATION

The operation, sensitivity, equipment manufacturers, estimated costs, advantages, disadvantages and limitations are described briefly for all potential inspection methods.* The intent here is to provide a basic overall description of the inspection methods from a user/operator point of view. Additional technical details of theory, equations, operation and specifications are available from the manufacturers in the noted references (See Table 3-1 and Section 6).

Appendix B is separated into nine major inspection areas. They are:

1. Visual,
2. Oil Spill Detectors,
3. Dynamic Insertion into OTS,
4. Corrosion,
5. Non-Destructive Testing,
6. Survey,
7. OTS Control,
8. Special Methods,
9. Miscellaneous.

Each major inspection area is described in a separate subsection that includes a description of applicable inspection methods**.

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* See also Table 3-1 for a comparison and brief description of the inspection methods.

** In certain cases, an inspection method might also be applicable to more than one major inspection area. To avoid excessive duplication, the method is described in only one major inspection area.

B.1 VISUAL INSPECTION

Visual inspection of deepwater port OTS components is accomplished primarily by inspectors stationed in the following areas:

1. On deck of ship (VLCC);
2. In launches or small boats that travel between ship, SPM, pumping platform and land;
3. On pumping platform ;
4. On SPM buoy;
5. On land;
6. In the air.

Visual inspections are also frequently carried out by divers for underwater components. Manned submersibles or remotely controlled inspection vehicles, although seldom used, may be effective for inspection of a few OTS components such as the undersea pipeline. Various types of remote visual inspection can also be used advantageously for some inspections. For example, a low-light TV can be installed on the SPM buoy or on the pumping platform with viewing of a video monitor on the shore or pumping platform.

Aids to simple visual inspection can enhance the effectiveness of simple visual monitoring. Some of the more effective aids include portable low-light TV with video monitoring and fluorescent lighting. These aids are particularly useful from the deck of a ship or for underwater inspection. Another method, that can be used advantageously, is the viewing of the inside of an OTS component with a flexible optical borehole device. Another visual aid is the use of tapes that are wrapped around OTS components such as hoses. Leaking oil from the hoses causes the tapes to change color resulting in easy visual detection by an observer.

Visual inspection can be used to detect small, incipient type oil leaks or external defects on components. Costs of this type of inspection are quite high, particularly when divers are required. Daytime visual inspection is adequate, under most conditions, for incipient failure detection of leaks. For example, small leaks at hose flange or kinking of hoses may be detected before a failure occurs that may lead to an oil spill incident. Visual inspection has many obvious limitations, it is not effective in bad weather, in fog or in darkness.

Visual inspection methods and procedures are described in the subsections that follow. Typical inspections are identified for each inspection method.

B.1.1 Visual Inspection From Launch

Principle of Operation

Visual inspection from a launch is carried out by providing a launch or small boat to travel between the VLCC, the SPM, and the platform and by using inspectors to visually inspect OTS components for leakage or damage. Lighting may be used at night to improve visibility.

Capability

Inspections are generally carried out for hose string, mooring system and SPM components. Visual inspections can be used to detect oil leakage and a number of other incipient failure indications such as external damage, connection or configuration errors, etc. that could lead to failure of an OTS component and result in an oil spill incident. This method can be carried out for a wide range of important inspections. Periodical visual inspections from the launch are given in Section 5.2.1.1, and continuous visual inspections are given in Section 5.2.1.3.

Sensitivity

The sensitivity of visual inspections from a launch is adequate, in many instances, to provide incipient failure detection such as observing improper hose configurations or finding small leaks at hose flange connections. However, the method is insensitive to internal or small surface defects that can cause failures in hoses, flange seals, etc. The method, in general, is sensitive to catastrophic failures, minor above-water oil spills and medium underwater spills. Sensitivity, of course, is limited to normal human sensing capabilities, primarily visual, hearing and smell.

Costs

Continuous visual inspection during a ship offloading can vary widely as discussed in Section 4.2. The major cost items include a manned launch, crew boat and terminal support personnel. Continuous visual inspections of the hose strings, SPM and mooring system for approximately 48 hours during a VLCC offloading is estimated to cost about $6200. Periodic inspections occurring every two hours is estimated to cost approximately $3600. Inspection costs on a yearly basis are expected to be quite high and may exceed $500,000. Daily continuous inspections may exceed costs of $1,000,000 over a period of a year. (See Tables 4-2 and 4-3).

Advantages

Continuous visual inspection from a launch appears to be the most effective overall inspection method currently in use. The main advantages of this method are that the method is extremely simple and it provides hundreds of inspections covering a wide range of OTS components which currently cannot be accomplished in a more effective manner by other inspection means.

B.1.1 (Continued)

Disadvantages and Limitations

The main disadvantages and limitations include the following:

(1) Cannot be used in bad weather;
(2) Not adequate in darkness;
(3) Subject to personnel error;
(4) Expensive;
(5) Does not provide adequate incipient failure detection of OTS components such as underwater hoses and pipelines;
(6) Difficulty in discriminating between an oil spill and the oil sheen from boat engines or a few liters of leakage at ship (this may spread over a wide area) or a small oil leak from an OTS component.

B.1.2 Visual Inspections on Deck of Ship

Principal of Operation

Visual inspections are carried out continuously by inspectors on the deck of the VLCC.

Capability

This type of inspection method provides continuous inspections on the ship during ship offloading. In addition, a number of inspections of the hose string and mooring system can also be carried out Typical continuous visual inspections from the deck of the ship are given in Section 5.2.1.2.

Sensitivity

The sensitivity of visual inspections from the deck of a ship is adequate, in many instances, to provide early detection of catastrophic failures such as ship breakout and also the detection of medium to major oil spills. The method provides only very limited incipient failure detection primarily because of the long distance (typically several hundred feet) between the inspector and many of the OTS components, particularly the hose string and mooring system.

Costs

Costs of continuous visual inspections from the deck of the ship are quite high and depend on the number of inspectors. Inspection costs for a single inspector on the deck of the ship are given in Tables 4-2 and 4-3. Inspections costs on a yearly basis are quite high and expected to range from $500,000 to $1,000,000.

Advantages

Continuous visual inspection from the deck of the ship provides essential inspections that cannot be carried out by other means. These essential inspections are mainly for the shipboard connections and the rail hose. The method is simple and provides some incipient failure detection for a few OTS components such as the rail hose.

Disadvantages

Disadvantages and limitations include the following:

(1) Inadequate in bad weather, fog and in darkness except for ship breakout;
(2) Subject to personnel error;
(3) Difficulty in discriminating between minor spills and thin oil sheen on surface of water (oil sheen can occur from a few liters of oil leakage and can cover a wide area);
(4) High cost;
(5) Provides no detection of internal or small defects of shipboard connections such as small cracks, corrosion or weld damage;
(6) Provides very little incipient failure inspections for the mooring system or hose string.

B.1.3 Visual Inspection by Divers

Principle of Operation

Underwater inspections carried out by divers and support personnel include the following general inspection operations:

1. Diver support equipment is provided from a boat and may include a diving bell lowered from the surface.

2. Extent and nature of marine growth recorded.

3. High pressure cleaning, wire brushing, sanding, etc. performed on underwater components prior to visual inspection.

4. Removal of debris, rocks, etc.

5. Tankers not moored to buoy and a calm state forecast for 48 hours unless indicated otherwise.

6. A diving platform may be required during certain sea states such as in choppy waters typically above 6-8 feet seas that occur in wintertime. (Diving platforms can be used in seas up to about 20 feet provided divers are lowered through the interface very quickly. Inspection below 60 feet can be carried out in choppy seas but little or no inspections can be carried out above 60 feet because of excessive diver movement. In many high sea states loading equipment from boat to platform is difficult. (Loading the platform by a helicopter would solve the problem.)

7. Early spring or early fall are inspection times recommended in the Gulf coast. Wintertime inspections are extremely difficult.

8. All U.S. diving regulations for offshore facilities should be observed.

Capability

Underwater visual inspections can be used to detect small amounts of oil leakage and a number of incipient failure indications. This method can be carried out for a wide range of important inspections. Typical visual inspections by divers are given in Section 5.2.1.7, 5.2.3.2 and 5.2.4.2.

B.1.3 (Continued)

Sensitivity

Diver inspections are of sufficient sensitivity to detect small amounts of oil leakage, external damage, configuration errors, etc. Underwater visual inspections, of course, are not as good as normal above water inspections. However, inspections with visual aids such as underwater lighting and hand-held low-light TV cameras result in adequate visibility for underwater inspections. Inspections are limited to maximum depths of about 600 meters.[10] Diver inspections at depths of 30 to 60 meters are routine. Further, diver inspections generally are effective to depths of about 300 meters. Limited inspections currently can be carried out between 300 and 600 meters.[10] However, recent work by Comex[50] indicates that inspections at those depths might be carried out with only minimal limitations.

Costs

Diver inspections are of medium cost. For example, inspection of the underbuoy hose string of a CALM SPM is expected to cost about $3000. Generally, underwater inspections by divers are cost effective to about 300 meters. Beyond that depth submersibles or other types of inspection methods should be used.

Advantages

This method provides good inspection for many OTS components. It is the only cost-effective method currently available for inspection of a number of important OTS components such as submarine hoses and submerged components of the SPM.

Disadvantages

A few of the important disadvantages and limitations of this inspection method are as follows:

(1) The frequency and degree of inspections of OTS components is limited primarily because of cost considerations;
(2) Not usually performed in fog, darkness and rough weather;
(3) Subject to personnel error;
(4) Photographic and video tape records sometimes are unreliable or difficult to interpret.

B.1.4 Submersibles - Manned or Remotely Controlled

Principle of Operation

Manned or remotely controlled submersibles, equipped with lights, video TV cameras, side-scan sonar, etc, can be used for visual underwater inspections. A wide variety of submersibles exist (for examples, see Reference 10) that travel underwater at relatively high speeds and can carry out inspections at depths that greatly exceed diver visual inspections. Remotely controlled vehicles are controlled by a surface ship with a winch and usually includes support and control equipment such as an armored control cable, a launch and recovery capsule and a tether cable attached directly to the submersible. Numerous manned submersibles exist. A typical two-man submersible (by Cooke Bros.), that could be used for DWP inspections, has a range of 25 miles, travels at about five knots and can be used to a depth of 180 meters.

Capability

Submersibles can be used for a wide range of inspections. However, their potential usage at deepwater ports is somewhat limited. This is because the depths of the pipeline, pumping platform and SPM are expected to be less than one hundred meters. At these depths, diver visual inspections provide more effective inspections and are also more cost-effective. One of the main uses of manned submersibles for DWP's is to quickly inspect the length of the undersea pipeline if oil leakage or damage is suspected, but the location is unknown. Also, the inspection method can provide quick and effective inspections of the undersea pipeline, pumping platform and SPM after a major catastrophy such as an earthquake. Remotely controlled vehicle inspection can be particularly useful for visual inspections of pumping platform structures and undersea pipelines that are located in very deep water (>300 meters).

Manufacturer and Cost Data

Manufacturers and operators of submersibles are included in Reference 10 and a few are given in Appendix A. Costs of inspections using submersibles are usually much higher than diver inspections and generally are not cost-effective if used in less than 300 meters of water. When fast and wide area underwater inspections are required, however, submersible inspections may be more cost-effective than diver inspections. The cost, for example, of inspection of 20 miles of undersea pipeline by a manned submersible is in excess of $100,000.

B.1.5(a) Visual Inspection on SPM Buoy

Principle of Operation

Visual inspections are carried out continuously by inspectors on the CALM SPM buoy at any time and periodically on the SALM SPM.

Capability

This inspection method provides a number of inspections that are similar to those carried out from the deck of the ship. Some of the main types of inspections are as follows:

1. Oil leaks at or near buoy
2. Some external hose string and mooring system defects near buoy
3. Orientation alignment and movement problems that can cause failure
4. Mooring system failures at buoy and along mooring line
5. Hose string leaks or rupture
6. SPM leaks

Other visual inspections on a SPM buoy are given in Section 5.2.3.1 and 5.2.4.1.

Sensitivity

The sensitivity of visual inspections from the SPM buoy is sufficient to provide early detection of catastrophic failures such as ship breakout and hose string rupture and also the detection of small to medium oil spills. The method provides good incipient failure detections because of the close proximity of the inspector to many of the OTS components, particularly the hose string and mooring system. Also the inspector can hear the sounds of oil leakage or the sound that occurs before rupture. In addition, the odors of oil leakage can also be detected.

Costs

Cost of continuous visual inspections are similar to those incurred using an inspector on the deck of the ship.

Advantages

(1) Simple
(2) Provides wide range of visual inspections
(3) Provides some useful incipient failure detection in fog or darkness

Disadvantages

(1) Medium cost
(2) Cannot be used in rough weather

B.1.5(a) (Continued)

(3) Subject to personnel error
(4) Could be hazardous to personnel
(5) Cannot be done on SALM because the SALM buoy is designed to submerge under heavy loads (if breakout occurred it would be extremely dangerous for the inspector).

B.1.5 (b) Visual Inspection on Pumping Platform

Principle of Operation

Visual inspection for oil leakage on the water is carried out continuously from the pumping platform.

Capability

The main capability of this method is the detection of minor to medium oil leaks on the surface of the water near the pumping platform and external damage of piping from undersea pipeline to the platform piping. Visual inspections can also be made for pumping platform OTS components.

Costs

Similar to costs for visual inspection from deck of ship.

Advantages

The main advantages of this inspection method are that it is simple and that it provides some incipient failure detection because of the capability to detect minor spills before a major oil spill incident occurs.

Disadvantages

The main disadvantages of this inspection method are:

(1) High cost;
(2) Difficulty in discriminating between thick oil slicks and a thin sheen.

B.1.6 Optical Borehole

Principle of Operation

A flexible fiberoptic viewing probe with a bright light is inserted into OTS components through flanges or other means for inspecting internal sections of OTS components. A bundle of flexible finely spun glass fibers is used to transmit light and images to and from the inspected area of the OTS component. An adjustable eyepiece lens is used for viewing by an inspector or for attachment to a camera for a permanent record. Up to 40,000 coated fibers that are 12 microns each are geometrically aligned in a single bundle to transmit the total image. Each fiber carries its own mosaic part of the total image and is coated with a mirror-like lower index of refracting glass which keeps the image within the individual fiber.

Other viewing probes that are not flexible can also be used. These probes use a light source for illumination of the inspected component and a scanning mirror system to view the image.

Capability

Optical borehole inspection can be used for internal visual inspection of many OTS components that cannot be suitably inspected by other means. Internal inspections of hose sections, chambers, pipelines, valves, machinery, etc. can be carried out. Inspections can also be carried out underwater.

Sensitivity

Viewing of 360^o in all planes can be accomplished. Photographs of the inspected area can be taken at the viewing port for a permanent record. System resolution varies depending upon specific unit, but a typical device has a resolution of 34 line pairs per mm.

Advantages

(1) Good incipient failure detection
(2) Commercially available
(3) Low cost
(4) Simple
(5) Perminent record
(6) Inspection of areas that cannot be inspected by other means

Disadvantages

(1) Requires that inspected area be emptied of oil

B.1.7 TV Monitor

Principle of Operation

TV monitoring is carried out by installing a TV camera above the water or underwater for continuous visual inspection of OTS components. Cameras can be either hand held by inspectors, automatically controlled for scanning over a broad area or placed in a stationary location. The camera's view can be visually observed on a television monitor, video recorded or photographed.

Capability

TV monitoring can be used for inspections from the SPM buoy (practical for CALM only), on the deck of the ship or on the pumping platform. Low-light TV cameras can be used for these inspections and can also be used by inspectors at these locations to aid visual inspections in darkness. The method can be used for a variety of inspections of OTS components such as:

TV MONITOR ON CALM BUOY

Hose String

(a) Oil leaks
(b) External damage
- kinking
- collapse
- safety blinker lights operating
- loss of buoyancy

(c) Fouling with each other
(d) Stream out and floating freely
(e) Damage to floatation medium
(f) Looseness or loss of assemblies
(g) Debris

Mooring System

(a) Ship breakout
(b) Impact damage
(c) Condition of rope floats
(d) Hawser entangled
(e) Hawser fouling
(f) Free streaming
(g) Loss of rope floats
(h) Loss of assemblies

SPM

(a) Oil leaks
(b) Loss of assemblies

TV MONITOR ON DECK OF SHIP (LOW-LIGHT TV)

Aids visual inspections in darkness
(see Section 5.2.1.2 for typical inspections)

B.1.7 (Continued)

TV MONITOR ON PUMPING PLATFORM

- Oil leakage
- Ship movements

Manufacturer and Cost Data

TV monitoring equipment is available from numerous companies. Costs for a TV monitoring system with low-light capability on the deck of a ship, on the SPM or the pumping platform typically range from about $10,000 to $25,000.

Advantages

Some of the main advantages are:

(1) Simple
(2) Wide area of coverage
(3) Operates at light levels that are inadequate for visual inspection
(4) Some incipient failure
(5) Commercially available
(6) Aids visual inspection on deck of ship, SPM and pumping platform
(7) Safe (no men must be topside in bad weather)

Disadvantages

One of the main disadvantages is that the method is not as effective as simple continuous visual inspection by an inspector on the deck of the ship, SPM and pumping platform. However, the inspection method may be suitable in some instances in reducing the number of inspectors. Also, the method is impractical for the SALM.

B.1.8 Tape Detection

Principle of Operation

A variety of types of tapes wrapped around hoses or other OTS components are potentially feasible for inspection of small amounts of oil leakage or excessive stress that are indicative of potential failure. Concepts such as blister, color change, tracer reactions, changes in resistance or capacitance are possible. These concepts entail electromechanical, electro-chemical and electroconductive effects on the tapes. Tapes that change color or tapes that change electrical characteristics appear most promising for hose strings. Examples of typical tapes are given in the following paragraphs.

Several elastic and viscoelastic materials are known whose electrical conductivity is a function of applied stress, for example, elastomeric epoxies filled with carbon or silver particles. If tape were applied and a leak should occur, a bulge or blister would result causing the tape to stretch. The stretched tape would have a higher resistivity and hence provide a simple detection system.

Electrical characteristics of a tape can change based upon electrochemical properties. A number of substances are known which will react with the hydrogen sulfide normally present in oil, and in so doing, cause a change of the capacitance or conductivity of the tape, for example, a tape that uses a heavy metal coordination complex of a polymeric ethylene diamine bis acetic acid. Hydrogen sulfide would cause precipitation of the heavy metal as the sulfide with concomitant liberation of free caroxylic acid groups. Such a reaction would cause a change in resistivity and dielectric properties.

Capability

Tape inspection methods can be applied to hoses, piping, chambers and structural members and can be used for periodic or continuous inspection of most OTS components. The technique has been used in industry primarily for inspection for excessive strain at stress points.

Costs

The cost of tapes that are effective in significantly reducing the oil spill risk, such as for hose strings, is expected to be quite expensive (about $450,000 for typical DWP with 6 SPM's) and are not commercially available. This high cost is caused by the high expected costs of the tape and its short life expectancy (few years). In addition, development costs that are required before a tape inspection system can be implemented are also expected to be very high.

Advantages

Some of the main advantages of this inspection method are:

B.1.8 (Continued)

(1) Simple inspection
(2) Good incipient failure detection
(3) Can be used underwater
(4) Can be used for continuous inspections
(5) Tape repair can be made with OTS component in-place but coatings would be difficult to repair or replace

Disadvantages

There are a number of major disadvantages of tape inspection.

(1) Tapes are not durable and excessive damage is expected particularly if the method is applied to hose strings or underwater OTS components.
(2) Cost of the inspections method are expected to be very high.
(3) Tapes are in the feasibility stage only.
(4) A number of practical problems exist:
   - oil from sources other than hose leaks may cause tapes to change color;
   - resue of the tape after exposure to oil may not be possible.

B.2 OIL SPILL DETECTORS

Oil spill detectors identified in Section 3 of this report are intended for detection of incipient failures; that is, for inspection of small oil leaks that are indicative that an OTS component is failing. Summary descriptions of these detectors are presented in Table 3-1 and are not discussed further here because much of the information is available in numerous reports such as NTIS Survey Report, NTIS IPS-76-0701, on oil pollution detection and sensing and in manufacturer's literature. Also, an oil spill research and development program has been an on-going project for the United States Coast Guard and Environmental Protection Agency for a number of years.

Oil spill detectors generally have not been used at deepwater ports. Affects of environment on these devices such as water velocity, turbidity, wave height, vibration, detector movement, safety considerations, etc. must be known before the device can be used. A number of oil spill detectors, those commercially available and others, have been improved in recent years and potentially can be used by deepwater ports. For example, commercial detectors for platforms and launches are available from Wright and Wright, Inc. Oil spill detectors for monitoring from the deck of the ship and pumping platform are available from Rambie, Inc., and Baird-Atomic, Inc. A number of other sources of oil spill detectors are given in Appendix A.

B.3 DYNAMIC INSERTION INTO OTS

Inspection methods included in this grouping are those that require insertion of a gas, fluid or a propelled inspection device either into or onto an OTS component. These inspection methods are intended to be used primarily for DWP inspection of OTS pipelines and hose strings.

Dynamic insertion OTS inspection methods, including dye tracing, inspection pigs, hydrostatic-pressure drop, reflected pressure wave, vacuum with TV inspection pig, external hydrostatic and acoustic resonance, are described in the following subsections.

B.3.1 Dye Tracing

Principle of Operation

A dye is inserted into hoses, pipelines or other OTS components that are filled with water and pressurized. When the dye leaks through a leaking component, it is detected either visually or electronically using a fluorometer. Commonly used dyes are red dyes such as Rhodomine W T, Rhodomine B or yellow-green fluorescent dyes.

Visual inspection using red dyes typically is carried out during the day when visibility is good. Fluorescent dyes are more difficult to see during the day because of the similar type background color of seawater. However, these dyes are easily seen in darkness with a hand held UV detector (light) either above the water or underwater.

A typical inspection operation would be to install a container over the inspected OTS component, insert a fluorocarbon dye under pressure into the OTS component and then pump the sampled water up a tube to a fluorometer detector in a boat. The inspection operation also could be carried out by using a diver to go along a pipeline or hose string with a suction hose and then pump the sampled water up to a fluorometer detector in a boat.

Capability

Dye inspection can be used for most DWP OTS components. It is particularly useful for hose strings, PLEM, fluid swivel, hose arm, undersea piping and undersea pipeline.

Sensitivity

Under ideal conditions, the dyes with a fluorometer are about 100 times more sensitive than visual observation of dyes and 10 to 100 times more sensitive under non-ideal conditions (high waves, currents, etc.). Leak sensitivity of about 1 part in 10^5 (at 10% of full scale) are easily detected using a fluorometer.

Manufacturer and Costs

Dyes are relatively inexpensive and commercially available from a number of manufacturers. Fluorometers are commercially available at a cost of approximately $5,000 or can be rented or leased.

Advantages

This method provides good incipient failure detection and is useful in locating very small leaks particularly in darkness. It is particularly advantageous in locating leaks in areas where components have residual oil from previous leaks or oil from external sources. This commonly occurs in areas such as in the soil above a pipeline that had previous leaks. The inspection is also useful when leakage seeps through the soil and bubbles from oil leaks are small or in such small quantities that they cannot be observed visually.

B.3.1 (Continued)

This method is also simple, of low cost and commercially available.

Disadvantages

This method usually is time consuming. It also requires that some components be out-of-service during inspection.

B.3.2 Inspection Pigs

A variety of inspection pigs using different operating principles can be used for internal inspection of the pipeline and in some instances, hoses. Inspection pigs include magnetic flux, Kaliper, active ultrasonic, passive ultrasonics, TV camera, camera, eddy current, ultrasonic imaging and infrared units. Most pigs are propelled through the pipeline by oil or other fluids flowing through the pipeline. A few types are pulled or pushed through the pipeline or hose. In large diameter pipelines, internal inspections can be carried out using inspectors. In this type of inspection, equipment and inspectors are propelled through the pipelines by vehicles ranging from a simple dolley pushed manually to a powered, controlled environment chamber with a wooden instrumentation trailer.

A pipeline cleaning pig, typically a brush type, and a dummy inspection pig should be run through the pipeline prior to actually running the instrumented inspection pigs. The pipeline should be inspected before the oil is initially transported to obtain a background. Calibration blocks for some types of inspection pigs should also be put on the pipeline to provide operational and sensitivity checks. Tracking systems for inspection pigs should also be used in case the inspection pig gets stuck in the pipeline or for identification of defective areas.

Magnetic flux inspection pigs, because of their wide usage, are specifically described in the following subsection. Information on other inspection pigs is given in part 3.2 of Table 3-1 or is available from the manufacturers identified in Appendix A.

B.3.2.1 Magnetic Flux

Principle of Operation

A magnetic field is induced into a pipe wall around the circumference and the field flows in a longitudinal direction. In an undamaged pipe, a smooth flow of magnetic lines of flux all remain within the pipe body wall. A damaged or unnatural area of the pipe affects the flow of the lines of flux, causes the flow to "bridge" across this area and creates a magnetic disturbance or flux leakage. This flux leakage is proportional to the size and depth of the damaged area.

One of the most widely used magnetic flux inspection pigs is the AMF Tuboscope Linalog. The instrumented pig uses electromagnets to induce the magnetic field, and it is sent through the pipelines, typically at a few miles per hour, propelled by oil or water flowing through the pipeline. This device is expected to be operable in salt water in 1979. A similar device, VETCOLOG PIG, is manufactured by VETCO Pipeline Services. This inspection pig uses permanent rather than electromagnets and can be used in oil, water and salt water. A magnetic tape recorder is installed in both inspection pigs and is used to store the electromagnetic data. Data tapes are then reduced and analyzed after the pigs are run through the pipeline.

Capability

Magnetic flux inspection pigs are the most widely used type of inspection pigs. The most important capability of the devices is that it can be used to measure the severity of corrosion. It can also be used to inspect for a variety of pipelines defects, including hardspots, manufacturing defects and flaws, girth welds, gouges, pits, etc., and can be used to help evaluate the effectiveness of the cathodic protection system.

Sensitivity

The sensitivity of the magnetic flux inspection pig is quite good for corrosion or pitting. Typically, it is graded in three ranges of corrosion severity: 15-30% of nominal wall; 30-50% of nominal wall; greater than 50% of nominal wall. Defects as small as 1/8-inch are claimed as detectable by the manufacturers.

Manufacturer and Costs

The manufacturers of these magnetic flux inspection pigs are AMF Tuboscope, Inc. and VETCO Pipeline Services. These devices are usually provided as an inspection service that includes inspection pig, operating personnel and data analysis. A typical cost for inspection of 20 miles of 36" pipeline is about $20,000. A similar type of inspection pig is currently under development in Canada.

B.3.2.1. (Continued)

Advantages

Advantages include the following:

(1) High reliability
(2) Locates defects
(3) Permanent record
(4) Monitors integrity of line
(5) Locates potential failures before they reach catastrophic failure
(6) Helps evaluate effectiveness of cathodic protection
(7) Commercially available

Disadvantages

These pigs, for large-diameter pipelines (i.e., 54 inches ID), have a high cost for periodic inspections which are usually carried out once or twice a year. Data records are difficult to interpret and require human interpretation. The electromagnetic type cannot determine if a defect is in the inside or outside of a pipe. The permanent magnet type can get stuck in a pipeline and is difficult to remove without cutting out a section of the pipeline. The devices do not adequately detect thin cracks. It is also possible to have anomalies that are difficult to interpret. For example, a weld that penetrates into pipe may result in cavitation downstream causing corrosion and erosion. The girth weld would be picked up but the adjacent anomalies might not show up because only one pulse from the device in that area may be monitored.

B.3.3 Hydrostatic - Pressure Drop (Pressure Difference or Pressure Level)

Principle of Operation

The pressure drop method of inspection uses pressure difference gages that are installed across a series of block valves that isolate sections of an empty pipeline or hose string. The empty sections are then pressurized, typically to 225 psi for hoses and 600 psi for pipelines. Pressure difference gages will indicate if a leak exists after a suitable period of time. Actual stabilization time depends upon the required tightness (leak rate allowed) of the system and temperature effects. Usually, a derivative $\frac{d\Delta p}{dt}$ is used to show the deviation of differential pressure as a function of time in order to simplify conclusions of leakage. Numerous types of pressure difference gages are commercially available for this measurement. Since pressure drops as a line cools, effects of temperature must be taken into account.

Variations of this inspection method can be made. One variation is to pressurize the DWP transfer line with gases such as helium to detect leaky areas with helium leak detectors. Passive ultrasonic detectors (B.5.1) and the passive acoustic array (B.8.1) can also be used to detect escaping gas. In another variation, the line could be pressurized and sections of the line closed off. Then the static pressure of each section could be accurately measured. This method can, to some extent, give incipient fault detection. At proof pressures slightly above normal operating pressures leaks may occur which would not normally occur and be detected until some later time at normal operating pressures.

Capability

This inspection method can be used for inspection of most of the major components of the OTS such as the pipeline, hose string, PLEM and SPM. The method is generally used for pipelines every two to five years in the United States. Pressure tests, however, are required by regulations as often as monthly in some European countries. Well maintained DWP's commonly use this inspection method from the hose string end to land on a weekly basis or before each ship visit when the DWP is used infrequently.

Advantages

This inspection method is simple, provides good incipient failure detection and is a widely used inspection technique. It is a low cost inspection when the system can be shut down without causing downtime as in the case for the hypothetical DWP described in this study.

Disadvantages

Some of the main disadvantages of this inspection method are:

B.3.3 (Continued)

(1) Requires out-of-service inspection
(2) Potentially can cause damage to OTS components if test pressure is excessive
(3) Requires leak detection method to locate leak
(4) Downtime required because of time for temperature stabilization can be of long duration (24 to 72 hours)

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B.3.4 Reflected Pressure Wave

Principle of Operation

This inspection method, developed by Shell Pipeline Research, uses sensors that detect a crack. The method requires that a hose section or pipeline section be first blocked off, filled with nitrogen and then pulsed with a pressure wave. The pressure wave reflects from the crack before it reflects from the end of the pipeline or hose. The crack location is determined by comparison of wave reflection times.

Capability

The method requires relatively smooth internal surfaces and can be used for inspection of the OTS pipeline. This inspection method is questionable for inspection of the OTS hose string because the hose/flange and flange/flange interfaces may appear as cracks, and it would be difficult to discriminate between a crack or cut in the inner lining of the hose string and these interfaces.

Sensitivity

Experimental test results by Shell Pipeline Research personnel indicate that the minimum noticable opening in a 12-inch line is about an inch.

Advantages

This inspection method does provide some incipient failure detection because cracks can be detected before they increase to a "hole through condition" and actually leak. Also the method is simple to carry out and is of low cost.

Disadvantages

Some of the main disadvantages and limitations of the reflected pressure wave inspection method are as follows:

(1) Requires out-of-service inspection
(2) Sensitive to internal surface roughness
(3) Experimental technique - not commercially available
(4) Currently has only been tested on small diameter pipelines
(5) Questionable for effective inspection for defects in hose string

B.3.5 Vacuum (With TV Inspection Pig)

Principle of Operation

This inspection method requires that a TV inspection camera pig be pulled or pushed through the hose string while it is emptied of oil and evacuated. The TV camera can be used for visual inspection of the inside of the hose string. Remote TV monitors and Videotaped data can be used by the inspectors to monitor the inspection and for permanent records. Evacuation of the hose allows for inspection of internal hose string damage that may not be visible at ambient pressure.

Capability

The vacuum (with TV inspection pig) method is capable of inspecting the interior of a hose string for defects such as blisters, bulges, separation of tube from carcass, tears, cuts and gouges.

Sensitivity

The sensitivity is similar to visual out-of-service inspection. However, effects of hose bending at the time of inspection are uncertain.

Manufacturer and Cost

TV inspection pig services are available from ABC Services and a few other companies. A major cost item for this inspection method is that of designing and building a system that can pull the camera through the hose string without damaging the hose and while maintaining a reasonably good vacuum (at least 15 inches of mercury). Estimated inspection costs for this inspection method are given in Table 4-2.

Advantages

The main advantages of this inspection method are that it is simple, low cost and potentially provides good incipient failure detection of internal hose damage which currently cannot be obtained by means other than onshore inspection.

Disadvantages

Two main disadvantages exist for this inspection method. First, there is potential difficulty in interpreting data because of hose bending effects at the time of inspection. Secondly, the inspection method is difficult to implement.

B.3.6 External Hydrostatic

Principle of Operation

External hydrostatic inspection is carried out by using a portable inspection device that fits over and seals a small section of pipe that is to be inspected. An internal pressure is applied to this sealed area and monitored. If an internal leak exists in the inspected component, a pressure decrease will occur and the leak detected. Inspections can be made quickly and the inspection device can be easily moved along exposed piping or pipelines. Relatively low pressures (less than 50 psi) are required for this inspection.

Capability

This inspection can currently be applied to above-water OTS components such as pipelines and piping for inspection of defects in threaded or welded connections. This inspection method potentially can be developed for underwater use for inspecting OTS components such as piping and chambers. The inspection method potentially can be developed for inspection of OTS components such as leaking flanged connections or leaks at the hose/nipple interface.

Sensitivity

The inspection method is more sensitive than hydrostatic testing because the inspection device can be applied directly to small sections of the pipeline.

Manufacturer and Costs

This inspection device (and/or service) is low cost and is available from World Wide Oil Tool, Inc.

Advantages

Some of the main advantages of this inspection method are as follows:

(1) Low cost (if pipeline accessible)
(2) Simple
(3) Potentially can be applied to hose flanges and underwater piping
(4) Good incipient failure detection
(5) Quick test time
(6) Commercially available
(7) More sensitive than hydrostatic testing

Disadvantages

The main disadvantage of this inspection method is that it must be applied externally to OTS components and thus cannot be used on buried or covered components. Also can be used only for a small area.

B.3.7 **Acoustic Resonance**

Principle of Operation

This inspection method locates cracks in the walls of gas-filled pipelines by using the "organ pipe" resonances of the gas column in the pipeline to measure the distance from the pipe input to a crack in the pipeline wall. A variable frequency sound generator and acoustic detector are located at the pipe input. Sounds at up to ten pipeline resonance frequencies are transmitted in the gas-filled pipeline. Resultant variations of sound levels are measured by the acoustic microphone and processed as a function of frequency. A crack can be located using

$$L = \frac{c}{2\Delta f},$$

where L = distance from the sound source to the crack,
c = velocity of sound in a gas,
Δf = is the average frequency spacing between overtones.

Capability

This method is capable of inspecting the integrity of OTS pipeline and piping and particularly useful in inspecting inaccessible areas such as the SPM undersea pipeline. The pipeline must be out-of-service during the inspection and ideally should be cleaned with a cleaning pig prior to a test. Acoustic resonance inspection has been successfully used in nuclear reactors to inspect the integrity of inaccessible gas lines.

Sensitivity

The sensitivity of this inspection method depends upon the pipeline radius and wall thickness and the wave length of sound in the pipeline. The sensitivity (minimum size hole radius detectable) can be estimated by

$$H_{r\,(min)} = R' + R'\,(R' + 1.18d)^{\frac{1}{2}},$$

where $H_{r(min)}$ = minimum detectable hole radius,
R = pipeline radius,
R' = $1.7\ R^2/\lambda$,
λ = wave length of sound in the gas column,
d = pipeline wall thickness.

Manufacturer and Cost

This inspection method was developed by Risley Engineering and Materials Laboratory in Great Britain. The equipment costs for the acoustic microphone, sound generator and auxiliary equipment is typically less than $10,000.

Advantages

Some of the main advantages of this inspection method are:

B.3.7 (Continued)

(1) Simple to implement
(2) Low cost
(3) Good incipient failure detection for pipeline and piping
(4) Particularly useful in inaccessible areas

Disadvantages

The main difficulties are that out-of-service inspection is required, trained personnel must operate equipment and the method can only be used for OTS pipelines and piping.

B.4 CORROSION

Inspection methods included in this section are used specifically for corrosion inspection. Other inspections, such as those described in Sections B.3, B.5 and B.9 and briefly summarized in Table 3-1, can also be applied for some types of corrosion inspection. For example, inspection of pipeline walls for thinning caused by corrosion can be accomplished by using various types of inspection methods such as inspection pigs, active ultrasonics, X-ray, etc. Corrosion inspection methods described in the following subsections include flow sampling, corrosion metering (internal and external) and typical manufacturer inspections.

B.4.1 Corrosion Flow Sampling

Principle of Operation

Inspection of pipeline corrosion by monitoring flow can be carried out by performing the following inspections:

(1) Corrosion rate coupon inspection
(2) Laboratory analysis of contents of flow
(3) Monitoring of strainer contents, pig traps returns, scrubber or separator, etc.

Corrosion rate coupons are usually weighed and then installed at the inlet and outlet of the pipeline. After a period of time, the coupons are removed, weighed and examined for corrosion. Corrosion rate is then given a quantitative valve by calculating the difference in weight over the inspection interval.

Laboratory analysis of flow is accomplished by analyzing the contents of samples (at inlet and outlet of pipelines) flow of the following:

(1) Iron content (indicates actual corrosion)
(2) Oxygen (significant component of corrosion process)
(3) Inhibitor (residual inhibitor correlated with injected inhibitor)
(4) Sediment (calcium, iron, magnesium, sulphides)
(5) Miscellaneous

Capability

Both corrosion rate coupons and laboratory analysis data are used primarily as trend indicators of the condition of the pipeline. This is also reason for examination of pig trap and strainer contents. In these inspections, however, miscellaneous internal damage to the pipeline, hose string and other OTS components can be detected by inspection of particles that break-off and are carried to the pumping platform or onshore.

Sensitivity

This inspection method can be used to accurately measure corrosion rate. However, this is a relative value and can only be used as a trend indicator of corrosion. In some instances, the inspection can be used to detect the existence of major corrosion.

Costs

Equipment required for these inspections is low cost (typically less than $5,000) and is commercially available from a number of companies. Inspections are of short duration and are generally carried out on a periodic schedule that typically range from weekly to monthly inspections.

B.4.1 (Continued)

Advantages

Some of the main advantages of this inspection method are:

(1) Provides some incipient failure detection
(2) Widely used
(3) Los cost
(4) All required instruments are commercially available

Disadvantages

The main disadvantage of this inspection method is that it is a general trend indicator and it is difficult to determine the amount of corrosion, quantitatively. Also, the method cannot be used to locate the site of the corrosion.

B.4.2(a) Corrosion Metering (Internal) - Corrosion Rate Probe

Principle of Operation

Inspection for corrosion rate can be accomplished by using a corrosion rate probe that is installed inside and at the top of the pipeline. The sensing element of the probe is left exposed to the flow. Corrosion causes the sensing to deteriorate and results in a change in electrical resistance. The formula for corrosion rate is known, thus the measured corrosion rate can be obtained.

Capability

The measured corrosion rate is used primarily as a trend indicator of the condition of the pipeline.

Sensitivity

This inspection method can be used to accurately measure corrosion rate. However, this rate is a relative value and can only be used as a trend indicator of corrosion. In some instances, this inspection can be used to indicate the existence of major corrosion.

Manufacturer and Cost

Equipment required for this inspection is of low cost (typically less than $3,000) and is commercially available from a number of manufacturers.

Advantages

Some of the main advantages of this inspection method are:

(1) Simple to implement and monitor data
(2) Provides some incipient failure detection
(3) Commercially available
(4) Low cost

Disadvantages

Some of the main disadvantages and limitations of this inspection method are:

(1) Trend indicator - difficult to obtain a useful quantitative value of the amount of corrosion
(2) Cannot be used to locate corrosion
(3) Probe replacement

B.4.2(b) Corrosion Metering (External)

Principle of Operation

External inspection for corrosion can be accomplished using corrosion meters. These meters usually are potential measuring devices. For underwater measurements, these meters typically consist of a hand-held probe connected to a voltmeter on deck. The probe typically contains a reference cell (silver-zinc, silver-silver chloride, copper sulfate) connected to a wire in the device's umbilical. Readings are taken with the probe held against exposed steel on the structure. Platform or piping to water readings are usually taken from permanent reference locations. These locations are usually determined from platform or pipeline potential profiles. Similarly, structure-to-earth DC potentials of underground pipeline, valves, etc. are also measured and recorded.

Potential profiles of OTS components should be computerized so that the OTS components can be adequately defined and suitable anode protection be added when needed. Inspections typically range from monthly to yearly depending on the particular component.

Capability

Inspections of corrosion using potential measuring devices provide adequate electrical measurement of the condition of the cathodic protection systems of all OTS components (pipelines, pumping platform, SPM, etc.).

Manufacturer and Costs

Potential measurement devices are commercially available from companies such as Bathycorrometer and Electronic Systems Design, Inc. These devices are low cost (typically less than $1,000).

Advantages

Some of the advantages of this inspection method are:

(1) Simple
(2) Low cost
(3) Widely used
(4) Good incipient failure detection
(5) Commercially available

Disadvantages

One disadvantage of this inspection method is that costly diver inspections are required for underwater OTS components. Also, there are no existing methods to reliably measure pipeline potential more than 5 miles offshore and in over 200 feet in depth. In deep water there is no practical way to obtain meaningful readings at mid points.

B.4.3 Holiday Detector

Principle of Operation

This is a portable hand-held inspection device that is used to inspect the coating of sections of an exposed pipeline. The device places an electric potential between the pipe and an electrode that is in contact with the outside coating of pipe. The electrode typically is a coiled spring wrapped around the pipe. The electric potential is set high enough so that an arc in air is produced when the thickness of pipeline coating is not satisfactory.

Capability

The main capability of this device is to inspect the integrity of exposed pipeline coatings. Defects such as thin coatings, coating discontinuities, and surface defects can be detected.

Sensitivity

This device detects pinhole defects of microscopic size.

Manufacturer and Cost

This inspection device is commercially available from Holiday Co.

Advantages

Some of the main advantages of this inspection method are:

(1) Simple
(2) Some incipient failure detection
(3) Commercially available
(4) Low cost
(5) Indicates if coating is less than ideal

Disadvantages

This method requires that the pipeline be uncovered and easily accessible.

B.4.4 Cathodic Protection (Manufacturer Schedule)

Principle of Operation

Inspections of the cathodic protection system should be carried out using manufacturer recommendations and schedule. Inspections typically recommended by manufacturers of the cathodic protection systems include:

(1) Impressed current systems should be checked daily for the proper voltage and amperage. If possible, the systems should be continuously monitored and properly alarmed in the event they are not operating. properly.

(2) Pumping platform to water potential readings at permanent reference points should be made at frequent intervals.

(3) Cathodic protection system of pipeline, SPM and other OTS components

   a. Check condition of system
   b. Frequent potential readings
   c. Exact count and estimation of anode wastage
   d. Check anode condition
      - size and depth of pits and cracks
      - security of anodes to mountings
      - external damage
         - chipping
         - holes
   e. Check insulating flanges
   f. Remove excess marine growth

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B.5 NON-DESTRUCTIVE TESTING (NDT)

A wide variety of non-destructive inspection methods, which are widely used and commercially available, can be applied for inspection of OTS components. Inspection methods which are both effective and have application to a large number of OTS components are described in the subsections that follow. Because of the importance of the use of underwater inspections in minimizing oil spill risks, effective underwater inspection methods are also included even though they may not be applicable for a large number of OTS components or for above water inspections. Other NDT methods with limited application to OTS components are identified in Section B.4.4. NDT methods and procedures for onshore inspection of deepwater port hoses are described in detail in References 48 and 51 and will not be repeated here. Special types of NDT methods that are not commonly used but are particularly effective for critical (high oil spill risk) OTS components are included in Section B.8.

B.5.1 Passive Ultrasonics

Principle of Operation

The passive ultrasonic inspection method uses any one of a wide range of portable passive detectors to convert the sonic and ultrasonic energy created by a leaking OTS component into an electrical signal. Leak location is determined by processing the electrical signal at various locations along the OTS component. Suitable detector signal conditioning and processing is used. Signal enhancement techniques are used to eliminate the background noise of fluid flow, machinery, etc.

Capability

Passive ultrasonic inspection can be used to inspect for leaks in a wide variety of OTS components including pipelines, hoses, valves, etc. The method can be used for both on-land and underwater inspections. Diver hand-held probes or detectors in a towed fish (pulled through the water a few feet above the inspected component) can be used for underwater inspections.

Sensitivity

The sensitivity of this method is difficult to quantify with a specific value. This is because the sensitivity depends on the particular OTS component and a number of factors such as pressure, flow rate, temperature, etc. Minor leaks, for example, in a burried pipeline can be detected at distances up to 100 meters.

Manufacturer and Cost

Passive ultrasonic inspection equipment and services are available from a number of companies. For example, detectors for on-land inspection of pipelines are available from TDW Pipeline Surveys and Magnaflux Corporation. Leak detector instruments typically cost less than $1,000. Underwater inspection services are less than $600 a day.

Advantages

Some of the main advantages of this inspection method are the following:

(1) Low cost
(2) Simple
(3) Commercially available for above water or underwater use
(4) Some incipient failure detection
(5) Provide leak location
(6) Supplements other inspection methods

B.5.1 (Continued)

Disadvantages

(1) Must be very close to leak source if it cannot be attached to leaking structure
(2) Leak location only
(3) Cannot be used to adequately determine severity of leak

B.5.2 Active Ultrasonics

Principle of Operation

In the active ultrasonics inspection method (sometimes called pulse echo method), a transmitter-receiver transducer is mounted on an external surface of a DWP component. The transducer sends ultrasonic wave pulses through or along the DWP component walls, and then detects distorted waves and reflection times of waves returned from defects (crack, flaw). Suitable transducer signal, conditioning and processing are used to convert the reflection times and the amplitudes of the reflected pulses into quantitative inspection records of flow dimensions and location.

Capability

Active ultrasonic inspection is one of the most widely used and most effective NDT inspection methods. It can be used for almost all DWP components and can be carried out during normal operations. The method can be applied to both on-land and underwater inspections.

This inspection method can be used to detect internal defects and variation in material, and it can also be used to measure wall thickness. Wall thickness measurements are extremely important because pipeline walls erode, and leaks can occur when they become too thin. Active ultrasonic provides excellent incipient fault detection because it can be used to detect faults before leaks occur.

Sensitivity

The sensitivity of this inspection is better than other comparable NDT methods for detection of internal defects. For example, internal defects that are 10 mm L x 1 mm W x 0.3 mm H can be detected at distances up to 2 meters away. Also, thickness variations of less than 1% can be detected easily.

Manufacturer and Cost

Active ultrasonic inspection equipment and services for both above water and underwater inspections are available from numerous companies. Cost generally is quite low compared, for example, with X-ray inspection. Equipment costs start at less than $1,000 but can vary greatly depending upon sensitivity, type of automation, etc.

B.5.2 (Continued)

Advantages

Some of the main advantages of active ultrasonic inspections are:

(1) Low cost
(2) Widely used inspection method
(3) Excellent incipient failure detection
(4) Works well underwater
(5) Can be used for most materials
(6) Commercially available

Disadvantages

The main disadvantage of this method is the difficulty in providing a test report of internal defects because of interpretation difficulty.

B.5.3 X-Ray

Principle of Operation

X-ray inspection is a radiographic method that uses X-rays (5 to 0.0004 A wave length) to penetrate through a material. Intensity of penetration is modified by passage through material and material defects. The contrast in the developed film between the image of an area containing a crack or flaw and the image of a defect-free area of the inspected part allows the inspector to distinguish a flaw. X-rays are invisible electromagnetic radiation that can penetrate matter, be differentially absorbed, travel in straight lines, produce photochemical effects in photographic emulsions and cause some substances to fluoresce. X-rays are produced when high speed electrons strike a metal target and a transfer of energy occurs.

Capability

X-ray inspection is one of the most widely used inspection methods for above water inspections. It has a wide range of applicability because X-rays can penetrate through almost any material and defects can be observed. It can be used for almost every DWP component. Defects can be detected at any depth into the material of DWP components. This inspection method is generally not used in underwater applications primarily because of the difficulties in using large source sizes and high voltages underwater. If used underwater, a captivated system is usually required because of the high absorbancy of X-rays by water.

Sensitivity

The sensitivity of the method is very good when compared with almost any other inspection method for detection of internal defects. Variations, however, are difficult to detect.

Manufacturer and Cost

X-ray inspection equipment and services for above water use are available from numerous companies. X-ray inspection equipment costs vary widely depending upon component testing. Costs start at a few thousand dollars. X-ray systems, however, can become very expensive depending upon requirements such as the size and material of the OTS component, type of automation, etc.

Advantages

Some of the main advantages of X-ray inspections are:

(1) Can be used for almost any material
(2) X-ray records are easy to interpret
(3) High reliability
(4) Commercially available
(5) Excellent incipient failure detection

B.5.3 (Continued)

Disadvantages

Some of the main disadvantages and limitations of X-ray inspection are as follows:

(1) Higher cost than most other non-destructive inspections
(2) Seldom used underwater because of the difficulties in working with high x-ray voltages and the high absorbancy of water
(3) Radiation safety measures are required
(4) Difficulty in detection of thin cracks in material
(5) Cumbersome equipment

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B.5.4 Radioactive Isotopes, Gamma Ray

Principle of Operation

Gamma-ray inspection is another radiographic method that uses a radioactive source (0.1 to 0.005 A wave length) to penetrate through a material. The method operation is essentially the same as X-ray inspection except that gamma rays are emitted during the disintegration of radioactive source material.

Operation underwater is carried out using a captivated system because water is opaque to Gamma-rays. The water is removed in a void area using a fixture such as an evacuated plexiglass chamber attached to the inspected component. The X-ray film is placed in a water-tight jacket on the backside of the inspected component. A radioisotope such as Iridium 192 is used as the source and placed on the other side or inside the structure to be inspected. The inside of the structure such as a hose or pipeline must be empty. The main objective of the captivated system is to remove the water so that the problem of penetration of Gamma-rays through water is eliminated.

Capability

Gamma-ray inspection is widely used for above water inspections particularly when a large range of component thickness must be inspected. It can be used for detection of internal defects in almost every DWP component. Defects such as voids, cracks, etc. can be detected that are located at any depth in the material. A major capability of this inspection method is that it can also be used for underwater inspection.

Sensitivity

The sensitivity of flaw detection gamma-ray inspection is not good as X-ray because of inherent lower image contrast. Gamma-rays, however, do allow a larger range of metal thickness to be recorded. The source must typically be within $\pm 7^{o}$ of defect.

Manufacturer and Cost

Gamma-ray inspection equipment or inspection services for above water use are available from numerous companies. Inspection equipment costs are similar to X-ray costs and vary a great deal depending upon the component tested and system automation requirements. In-place inspection costs are quite high when compared to other non-destructive inspection methods.

B.5.4 (Continued)

Underwater inspection services are available from Magnaflux Corp. and a few other companies. Rental of Gamma X-ray equipment and the use of an inspection technician costs about $300 a day.

Advantages

Gamma-ray inspection has essentially the same inspection advantages as X-ray. However, there are a few advantages over X-ray inspection. The main advantage for DWP use is that this method can be easily adapted for underwater inspection because of the small source size and the fact that no external voltage for the radioactive source is required. Another advantage is that the equipment is much smaller than X-ray equipment and allows inspection at component locations that are difficult to inspect with the larger X-ray sources.

Disadvantages

Gamma-ray disadvantages are similar to X-ray inspection. In addition, the inspections are somewhat slower and of lower radiographic quality.

B.5.5 Magnetic Particle

Principle of Operation

Magnetic particle method consists of magnetizing the material to be inspected and application of magnetic particles or powder that can either be dry or suspended in a liquid. If a crack or other flaw lies sufficiently close to the surface, the magnetic particles will deposit themselves along a crack because of the leakage in the magnetic flux at the discontinuity in the material that was not previously visible. A flaw will set up a pair of magnetic poles and the particles are attracted and held by the leakage flux, thus forming a visible indication of the flaw. For underwater use, magnetic particles are mixed with fluorescent agents, and an ultraviolet light source is used to produce good contrast between particles gathering around the crack and dark surroundings. The surface condition of the inspected area must be clean. Wire brushing, sanding, or high pressure cleaning techniques are usually applied.

Capability

The method is widely used in non-destructive testing and is suitable only for ferromagnetic materials such as steel and cast iron. It has a wider range of applicability than penetrants. Paint or other coatings do not appreciably interfere with defect detection for layers less than .1 mm thick. Essentially all types of defects can be found both at the surface and subsurface.

Sensitivity

Surface defects usually produce sharp and tightly held powder patterns while subsurface defects produce less tightly defined powder patterns that are less tightly held. Hence, severity of a flaw can be detected. The size of the flaw detected depends upon the strength of the leakage field produced by the defect. Generally dry particle techniques produce the greatest sensitivity. This method is highly sensitive for surface or subsurface flaws.

Manufacturer and Cost

In-place inspection of ferromagnetic components is relatively low cost. Inspection equipment basically includes a power supply, probes and magnetic powder. Cost for above water inspection equipment is in the $1,000 to $3,000 range, depending upon technique or inspection. Services that include inspectors and equipment are available at costs of less than $500 a day.

Magnetic particle inspection equipment for underwater use is currently not available for purchase but can be rented, leased, or built from designs supplied from foreign companies such as Det Norske Veritas. Magnetic particle inspection units for underwater use currently are very large and weigh in excess of one ton.

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B.5.5 (Continued)

Advantages

Magnetic particle inspection for almost any type of defects is almost completely free from restrictions such as size, shape and composition. It is a relatively simple technique even for underwater application. It is currently the most reliable underwater technique for crack and flaw detection.

Disadvantages

The main disadvantage is that the technique can only be used on ferromagnetic materials. Also, only estimates of the size and severity of the defect are possible with this method. Other disadvantages are:

(1) Sudden changes in permeability produce false defects
(2) Medium cost underwater
(3) Poor permanent records if underwater photos required
(4) Demagnitization is usually required
(5) Limitations covered by cost, portability, reliability and ease of implementations for underwater use (These limitations can be eliminated by further development. However, development is not cost-effective for DWP applications, alone).

4

B.5.6 Magnetic Rubber

Principle of Operation

Magnetic rubber inspection is a special technique that employs the same principle of operation as magnetic particle. Instead of using a powder suspended in a liquid vehicle, however, a black magnetic powder is suspended in a rubber vehicle. Leakage fields in a crack cause magnetic particles in the rubber to migrate and accumulate on the crack. A trace of the defect is first formed, then after the rubber cures it can be removed. A permanent clear trace of the black magnetic powder corresponding to the defect remains on the rubber mold. The mold can then be examined visually by a microscope at up to 100x magnification.

Capability

This method is for inspection of surface and subsurface cracks and other defects in ferromagnetic materials that lie inside small confined areas. The method also overcomes difficulties of providing surface illumination and visual inspection.

Sensitivity

This technique is more sensitive than magnetic particle primarily because a long time is available to allow the magnetic particles to accumulate on the structure. The magnetic fields attract particles slowly to the structure without any disturbing flow of liquids. The long migration times allows the use of weaker field intensities. Thus a great increase in sensitivity can be obtained. Defects of 0.10 to 0.15 mm in length are easily identified.

Manufacturer

This inspection method is commercially available from Magnetic Rubber Inc. and is a proprietary, patent-pending technique. Costs other than for the magnetic suspended particles in a rubber vehicle are similar to the magnetic particle method. For some inspections, however, the lower magnetic field requirements may reduce the equipment costs slightly.

Advantages

Magnetic rubber inspection techniques have the same advantages as the previously described magnetic particle method in Appendix B.5.5. Additionally, this inspection technique includes the advantages of a better permanent record and greater sensitivity, and can be used in small confined areas or in areas of poor illumination or visual inspection difficulties.

B.5.6 (Continued)

Disadvantages

The disadvantages are the same as those given for magnetic particle inspection. The method can be used underwater but has not been widely applied in deepwater port applications. Information on sensitivity and reliability for DWP underwater application is needed.

B.5.7 Magnetic Foil or Tape

Principle of Operation

Magnetic foil inspection is a special technique for underwater use that employs the same principle of operation as magnetic particle inspection. Instead of using a powder suspended in a liquid vehicle, the diver takes down a skin (a flexible sheet or tape) and then places magnetic particle crystals on the skin. The inspected structure is then polarized with electric current to produce the magnetic field. A fluorescent dye is applied to the area and the dye holds to the crystals which have formed a pattern on the skin. If a crack is present, it is then visible to the diver. A photograph is then taken for a permanent record. The technique is fairly slow as the foil must be applied to each part of the structure. Permanent records can be obtained by taking underwater photographs of the skin or by video tape.

Capability

This method allows for inspection of surface and subsurface cracks on almost any ferromagnetic underwater structure.

Sensitivity

This technique is less sensitive than either the magnetic particle or magnetic rubber method but does provide for inspection of small cracks that are detectable by visual inspection.

Manufacturer and Cost

This inspection method is currently unavailable for purchase but equipment and services can be rented or leased from foreign inspection companies. Inspection units are very large and weigh in excess of one ton. Costs are somewhat lower than magnetic particle.

Advantages

Magnetic foil inspection technique has the same advantage is as the previously described magnetic particle method (Appendix B.5.5). Additionally, this inspection technique includes the advantage of an improved permanent record for underwater use.

Disadvantages

The main disadvantages of this method are:

(1) Can only be used on ferromagnetic materials
(2) Sudden changes in permeability produce false defects

B.5.8 Ultrasonic Imaging (Holographic)

Principle of Operation

Ultrasonic imaging[19] is a NDT inspection method that provides simultaneous three-dimensional images of the interior of the solid surface of an OTS component. A focused ultrasonic transducer or transducer array is used to scan the entire volume of the inspected component with ultrasound. After scanning, the images can be tilted and rotated so that the flaw conditions can be viewed from an infinite number of orientations.

The transducers emit ultrasound and receive the ultrasonic reflections from either the interior or surface of the inspected component. An electronic processor generates an electronically simulated time-based reference signal by splitting a portion of the transmitted ultrasonic signal and sending it through a phase-shifting network. The simulated reference signal is mixed with the object signal in the processor and results in amplitude data combined with a phase analog of the time (depth) data of the internal properties of the inspected component at any given point in the transducers scanning pattern. Phase and amplitude data gathered in this way are the same type of information recorded by a hologram. Hence, these data are in the form of holographic signal (three-dimensional) and can be written in various formats into several storage oscilloscopes, magnetic tape and hard copy printers.

Capability

Ultrasonic imaging inspection can be used for both on-land and underwater inspections of almost any OTS component. Defects can be detected in three dimensions at any depth into the material of an inspected component. Defects such as corrosion, erosion, pits, thin cracks, loss of material on inside or outside of pipe or pipe weld can be detected.

Sensitivity

Typical sensitivities claimed by the manufacturer are as follows:

(1) Flaw areas of about 0.2 mm x 0.2 mm can be detected
(2) Instrument can be set up to meet any API specification
(3) Thickness resolution of about 0.05 mm
(4) Provides length, width, shape and depth of crack
(5) Penetrates to about 1 meter in solid steel or 0.3 meters of rubber

B.5.8 (Continued)

Manufacturer and Cost

Ultrasonic imaging equipment for inspection of OTS components such as the exterior of a pipeline, inside of a pipeline, tanks, underwater structures, etc. is available from Holosonics, Inc. This equipment is of higher cost than the other NDT equipment described in Section B.5. Specific cost of equipment and/or services are available from the manufacturer.

Advantages

Some of the main advantages of ultrasonic imaging inspection are as follows:

(1) Good hard copy picture of internal flaws with little or no interpretation of data required
(2) Has been used underwater with good success
(3) Device can be hand held or attached to pipeline
(4) Excellent incipient failure detection
(5) Expected to be commercially available in 1978 or 1979
(6) Potentially can be used for hoses particularly at nipple section
(7) Simple interpretation of data
(8) Can be used to measure exact size of flaw
(9) Shows thin horizontal cracks that radiography may miss

Disadvantages

The main disadvantages are:

(1) Higher cost than other NDT methods
(2) Device has been used successfully for a number of underwater applications but needs engineering design for specific application
(3) Reliability and performance specifications are uncertain at this time

B.5.9 Eddy Current

Principle of Operation

Eddy current inspection[25] is applied by using a detector coil that carries alternating current. The detector is brought near a metal material specimen, and eddy currents are induced in the metal by electromagnetic induction. The magnitude of the induced eddy current depends upon the magnitude and frequency of the alternating current, the electrical conductivity, magnetic permeability, shape of the specimen, the relative position of coil and specimens, the geometry and magnetic characteristic of the probe and the presence of discontinuities or inhomogeneities in the specimen. The induced eddy current opposes the original magnetic field. This causes the impedance of the exciting detector coil or any coil in close proximity to be affected. A defect causes the impedance to change. This impedance change is measured and the flaw detected.

Inspection schemes[24] such as the following are generally used:

(1) Inspection of cracks
(2) If crack detected, blend crack
(3) Reinspection
(4) If no other cracks found, make an insurance cut of about .7 mm deep

Also, if crack depth d is

d<.4 mm -- blend crack, no more inspection required
d.4<d<1 mm -- blend crack, inspect after 3000 hours operation
1 mm<d<6 mm -- inspect after 500 operational hours
6 mm<d -- replace component

Capability

Eddy current devices are used to detect cracks, voids and other flaws and to measure wall thickness; to inspect coatings when coatings are on steel surfaces; etc. They can be used on the inside of short lengths of pipe and other structures that are above or underwater and are of electrically conducting material such as steel. The devices are simple to operate, can be automated and can be used on either side of a pipeline wall or structure.

Sensitivity

Sensitivity of eddy current inspection equipment is usually defined as the needle deflection of the impedance measuring device in the presence of a crack. Minimum crack depths with usual equipment for above water testing is about 0.2 to 0.4 mm. More sophisticated equipment*has indicated defects 0.07 mm deep and 0.8 mm long.

Underwater inspections can also be carried out using eddy current devices. Cracks down to about .4 mm wide and about 10 mm long can be detected.

* W. Fortsch, "Automated Eddy Current Inspection," 9th EACMT Meeting (Helsinki, 1973)

B.5.9 (Continued)

Manufacturer and Cost

Eddy current inspection equipment for above water use is available from a number of non-destructive inspection equipment companies at costs typically ranging from about $500 to $5,000.

A few devices are available for underwater use. One developed by Inertial Switch, Ltd., is hand-held by divers.

The Branson Probolog[11] inspection device is sent through the pipe on a standard 30-foot cable to locate and record wall thinning due to crack pits and other flaws and also to inspect weld quality. the device cannot be used for long lengths of pipe. The probolog is widely used in industry.

Advantages

Eddy current inspection is of lower cost and simpler to use than most other comparable NDT inspection methods for inspection such as those required to be very close to a surface or for thin materials. The method is widely used in non-destructive testing.

Disadvantages

There are two main disadvantages of this method. First, it cannot be used for non-metals. Secondly, in many inspections acceptable variations in the quality of a specimen may cause a greater effect on the flow of eddy currents than an unacceptable defect.

Eddy current inspection for underwater applications is used primarily for smooth and flat surfaces, and there has been little use of it on tubular members. This method is primarily in the development stage. Shell oil, for example, has been doing the experimental work in this area for the last few years. Currently, one must establish a profile for a tubular member or series of tubular members under different conditions by monitoring periodically over a period of time. For tubular members near the surface, marine growth will grow and possibly change the signature of structure and potentially mask a serious defect. More development of this inspection method for underwater use is required to both improve the inspection capability and measurement effectiveness (reliability).

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B.5.10 Penetrants

Principle of Operation

Liquid penetrant inspection requires that the inspected part be degreased and wiped clean. Then a liquid penetrant is applied to the surface to be inspected. After sufficient penetrating time the excess penetrant is wiped off the surface and a white powder applied to the surface. After an additional period of time the penetrant seeps out of a crack and reduces the whiteness of the powder so that the defect can be observed. Other penetrants require blowing excess penetrants with water and inspections with movable black-light. Penetrants include various liquids such as red liquids and fluorescent liquids that are either water-washable or non-washable, and radioactive materials.

Capability

This inspection method is widely used for inspections and can be applied to almost every metal, alloy, plastic material, ceramic, rubber, etc., provided they do not have extremely porous surfaces. Direct surface defects such as cracks, laps, pits, porosity, etc. or internal defects with surface opening can be detected. It can only be used underwater if a dry habitat is available.

Sensitivity

The visual trace of the defect observed is always larger than the defect itself but the length of the observed defect is about the same. Sensitivity varies depending upon the specific technique that is used. Defects of 1 mm or less in width can be detected.

Manufacturer and Cost

Liquid penetrant inspection equipment is available from a number of non-destructive inspection companies. In-place inspection costs are very low and can range from a few dollars for the liquid penetrants and powders to less than $1000 for fluorescence dyes with black lights, developers and drying equipment.

Advantages

The main advantage of this method is that it is the simplest NDT method other than visual inspection. Also, relatively large areas can be inspected in short periods of time and at low cost.

Disadvantages

Penetrants are not applicable or will not work well with surfaces treated with paint, plating or other coatings that prevent penetrants from entering the defects. Surfaces also must be free of oil or grease. In most instances, internal defects cannot be detected or quantified. However, internal defects extending to a surface opening can be detected.

B.5.10 (Continued)

At this time, penetrants cannot be used underwater. Development of this method for underwater use is highly desirable because of its low cost, simplicity, wide area of coverage, and its increased sensitivity over visual inspection. However, development is not cost-effective for DWP applications, alone, and cannot be specifically recommended.

B.6 SURVEY

Survey inspection methods described in this section pertain to inspection of OTS components located either on or buried in the soil of the seabottom.

Sonar methods using towfish techniques for inspection of pipeline bare surface and depth of burial are initially described. Then, inspection methods for location of all OTS components (including pipelines) using divers, diver-aided inspections and inspection systems located on surface ships are described. Finally a description of scour inspections is given for methods that require a diver, inspection aids for the diver and continuously monitoring systems.

B.6.1(a) Side Scan Sonar

Principle of Operation

Side scan or side looking sonar is a type of sonar echo technique which is used for inspection of topographical features. Side scan sonar uses a short pulsed acoustic beam with its main axis tilted slightly off the horizontal toward the bottom. The beam that is generated is very narrow (typically 1°) in the horizontal plane and very broad in the vertical plane (typically 30°). The acoustic transducer that generates the beam is mounted in a mechanical towed fish that is located on or near the bottom surface at some distance behind a pulling boat. The towfish is usually towed a few meters above the surface bottom to eliminate surface reflections. The short pulse transmission and narrow beam give high resolution capability of topographical features. The acoustic pulse is reflected from an object along the horizontal path. The strength of the reflected echo depends upon the object's reflectivity, size and orientation relative to the beam. The reflected pulse is amplified in the towfish receiver and sent up the tow cable to a recorder in the pulling boat. The signal is then processed, and a permanent record is made on a recorder.

Capability

The main capability of this inspection method for DWP use is that it can be used to inspect for any exposure of the buried undersea pipeline. The method can also be used for mapping exposed undersea pipelines.

Sensitivity

Exposed surfaces as small as 1 inch can be detected for buried undersea pipeline.

Manufacturer and Costs

Side scan sonar systems are available for purchase from a number of companies such as Ocean Research Equipment, Inc.,(ORE) and Klein Associates, Inc., at costs of less than $20,000. Inspection services are also available at costs of about $750 (including operator) a day.

Advantages

Some of the main advantages are:

(1) Provides excellent incipient failure detection
(2) Fast inspection - requires about 5 days to inspect 60 miles of undersea pipeline
(3) Covers wide area
(4) Low cost
(5) Commercial systems or services are available
(6) Method can be used simultaneously with sub-bottom profiling inspection to obtain depth of pipeline burial

B.6.1(a) (Continued)

Disadvantages

Requires skilled interpretation of data

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B.6.1(b) Sonar-Penetrating (Sub-Bottom Profiling)

Principle of Operation

Penetrating sonar or sub-bottom profiling is a type of sonar echo technique which is used primarily for inspection of the depth of burial of undersea pipelines. Penetrating sonar uses two acoustical transducers that send pulsed, vertical, acoustic beams onto and into the soil above a buried undersea pipeline. One transducer transmits at a frequency that allows the beam to penetrate through the soil and reflect from the pipeline external surface. The other transducer transmits at a frequency that causes the beam to reflect from the soil above the pipeline. The strength of these reflected echos allow processing so that the depth of the pipeline and depth of soil above the pipeline can be measured and the resultant depth of soil above the pipeline can be computed. The acoustic transducers are mounted in a mechanical towfish that is located near the bottom surface and at a suitable distance behind a pulling boat equipped with a winch. The reflected pulses are amplified in the towfish receivers and sent up the towing cable to a receiver in the pulling boat. The signals are processed and a permanent record is made on a recorder.

Capability

The main inspection capability of this method is to measure the depth of burial of a buried undersea pipeline. The method can also provide trench delineation, pipeline location and pipeline orientation.

Sensitivity

Depth of pipeline burial can be measured to within approximately 5 cm.

Manufacturer and Costs

Penetrating sonar systems with sub-bottom profiling are available for purchase from a number of companies such a Ocean Research Equipment, Inc., Edo Western, Corporation and Raytheon's Ocean Systems Center at costs of less than $30,000. Inspection services are also available at costs of about $750 (including operator) a day.

Advantages

Some of the main advantages are:

(1) Provides excellent incipient failure detection
(2) Fast inspection
(3) Covers wide area
(4) Low cost
(5) Commercial systems or services available
(6) Method can be used simultaneously with side scan sonar to also inspect for exposure of buried pipeline

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B.6.1(b) (Continued)

Disadvantages

Requires skilled interpretation of data

B.6.2(a) Surveying - Diver Using Microwave Positioning System

Principle of Operation

An inspection diver walks the undersea pipeline holding a taut buoy line. A microwave positioning system is installed in the diver supply boat. An antenna, mounted on the side of the supply boat and over the buoy line, is used to accurately locate the position of the diver. In the case of a buried undersea pipeline, the diver also uses a hand-held sonar device to locate the pipeline while walking the line.

Capability

The main capability of this inspection method is to accurately locate the pipeline. Other inspections such as examination for pipeline damage and scour can also be carried out by the diver. Inspections of about 1/2 mile of pipeline can typically be carried out in one day.

Sensitivity

Precise pipeline location at depths up to 20 meters.

Manufacturer and Costs

The cost of this type of inspection is expected to be lower than existing methods according to Oceaneering International, the developer of the inspection technique (See Reference 32).

Advantages

Some of the main advantages are:

(1) Covers up to about 1/2 mile per day
(2) Can be used in turbid water
(3) Provides visual inspection by diver
(4) Particularly useful for new pipelines
(5) Excellent incipient failure detection
(6) Inspection services are available

Disadvantages

This inspection method is of high cost for undersea pipelines that are more than a few miles long. Also, the water depth limitation of 20 meters severely limits the use of this inspection method.

B.6.2(b) Surveying - Diver with Acoustic Transponder

Principle of Operation

An inspection diver walks the undersea pipeline. The diver uses a hand-held acoustic transponder with a narrow beam (typically 1°) signal to identify his precise location. An acoustic receiver system located on the diver supply boat is used to monitor the transponder location and provides a permanent location. In the case of a buried undersea pipeline, the diver also uses a hand-held sonar device to locate the pipeline.

Capability

The main capability of this inspection method is to accurately locate the pipeline. Other inspections such as examination of the pipeline for damage and scour can also be carried out by the diver. In addition, the diver can leave a spare locating transponder at the area where the pipe needs repair. This also provides easy location when repairs are made at a later time.

Sensitivity

Precise pipeline location at depths to 200 meters are expected using this inspection method.

Manufacturer and Costs

This inspection method is currently in the developmental stage (Reference 32). The transponder with 1° sonar beam is available from Wesmar Company.

Advantages

Some of the main advantages are:

(1) Inspection of up to 1/2 mile of pipeline per day
(2) Can be used in turbid water
(3) Provides visual inspection by diver
(4) Particularly useful for new undersea pipelines
(5) Excellent incipient failure detection
(6) Provides easy location of damaged pipeline areas

Disadvantages

This inspection method is expected to be of high cost for long pipelines and is in the developmental stage.

B.6.2(c) Surveying - Component Location - Miscellaneous Methods

A variety of systems, not discussed previously, are commercially available or in the developmental stage for inspection of the location of OTS components such as undersea pipeline, PLEM base, SPM buoy position, anchor chain pilings, etc. These inspection methods are expected to be seldom used for inspection of DWP OTS components. Hence, typical inspection methods will only be identified in the following list:

(1) Sonar on surface ship (commercially available)
(2) Doppler sonar on surface ship (commercially available)
(3) Phased array sonar on surface ship
(4) Diver hand held sonar (commercially available)
(5) Acoustic transponder at OTS component with acoustic receiver system on surface ship (commercially available)
(6) Magnetometer on surface ship (commercially available)
(7) Magnetic beacon transponder at OTS component with magnetometer on surface ship (Reference 30)
(8) Very low frequency radio beacon at OTS component with very low frequency receiver on surface ship (Reference 30)

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B.6.3(a) Scour - Diver Visual Inspection

Principle of Operation

Diver visually inspects for scour using visual inspection or visual inspection aided by underwater lighting. See Section B.1.3 and Section 5.2.5 of the main report for typical diver operations during these inspections.

Capability

Diver inspections for scour can be used primarily to identify unprotected areas of underwater OTS components caused by scouring and that potentially can result in excessive corrosion.

Advantages

Some of the main advantages are:

(1) Simple,
(2) Quick inspection-typically a few minutes for many OTS components,
(3) Low cost,
(4) Some incipient failure detection.

Disadvantages

Some of the main disadvantages of this inspection method are:

(1) Subject to interpretation,
(2) Cannot identify scour areas that may be covered up after a storm,
(3) Does not provide quantitative values for changes in soil levels, scoured areas of OTS components, etc.

B.6.3(b) Scour - Diver Inspections with Pneumofathometer Device

Principle of Operation

This inspection method is used to quantitatively identify scouring or drifts in areas surrounding OTS components or structures on the ocean floor. A pressure gage, calibrated in feet of sea water by pressure, is located on a diver support boat. Air is forced down a small diameter hose and is usually attached to the diver's hose but can be attached to anything near the bottom surface. If attached to the diver's hose, it can be held at the end in the diver's hand. The column of air under the pressure of sea water will give a depth reading at the gage located on the support boat. Readings are usually taken at the OTS component and then at distances such as 1, 2, 5 and 10 meters away. From these readings, one can survey the topography at and near on OTS component at the sea bottom. The readings at each location and are the visual condition of the soil and the OTS component at the sea bottom are recorded.

Capability

Topography of all underwater OTS components such as the pumping platform structure, PLEM base, PLEM and chain anchors, pilings, etc.

Manufacturer and Costs

Costs are low because measurements can be typically made in less than an hour.

Advantages

This inspection method is relatively simple to carry out and of low cost. The method provides some incipient failure detection because accurate sea bottom topography measurements can be obtained; OTS components that are located in areas where soil does not provide proper support or is eroding can be identified.

Disadvantages

The main disadvantage is that scour areas that can weaken structure supports, etc. may be covered up after a storm and may not be detected by inspections.

B.6.3(c) Scour - Continuous Inspection Systems

Principle of Operation

Inspection systems can be built or developed that continuously monitor scouring of OTS components. These systems, for most inspections, are not cost-effective and do not significantly reduce the risk of oil spills for the OTS. In isolated instances, this inspection method might be needed. Hence, typical inspection methods will be described only briefly in the following paragraphs.

An electrode resistance depth-measuring system (Reference 29) requiring an array of electrodes is placed below the ocean bottom to a depth which should exceed the expected depth of scour. AC voltage is applied to the electrodes in reference to a common ground, which is placed in water. An electronic system is used to detect the difference of impedance between reference ground electrodes when they are in water or buried in the soil. The system should be installed during DWP installation for optimizing the system effectiveness and reducing costs.

A magnetic beacon system (Reference 30) requires that a magnet (magnetic beacon or transponder) be permanently placed in a potential scour hole. The location and depth of the beacon are obtained using a sensitive magnetometer on the deck of the pumping platform, SPM, etc. The magnet could either be a permanent one or a DC electromagnet.

As electromagnetic beacon system (Reference 30) requires that an electromagnetic radio beacon be permanently placed in a potential scour hole. The location and depth of the beacon are obtained using a unique receiver system located out of the water near the beacon. The receiver system uses a continuous wave phase measuring technique.

An acoustic transducer installed at the ocean bottom is used to detect the sounds of bubble collapse that are generated at the onset of scour. See Reference 29 for a description of this technique.

B.6.3(c) (Continued)

Capability

Continuous scour inspection of most OTS underwater components such as the PLEM base, pumping platform base, pilings, etc.

Manufacturer and Costs

Continuous scour inspection systems generally are not commercially available. Most components of these systems are commercially available. Thus, only engineering design, installation and small development costs are required. Costs will not be given here because these vary widely depending upon OTS components and DWP design.

Advantages

(1) Detects scour areas that may weaken structure but may be covered up by storm
(2) Continuous monitoring
(3) Especially useful in deepwater where diver or submersible vehicle inspections are costly
(4) Good incipient failure detection

Disadvantages

(1) Medium cost
(2) Not particularly advantageous at short depths (i.e., 50 meters) from a cost consideration
(3) Systems require development and engineering design

B.7 OTS Control

Systems controlling the transfer of oil from ship to onshore storage terminals can be used for inspection. For example, an OTS control system with continuous pressure monitoring can be used for detection of hose string leakage or potentially to detect hose string defects (i.e., excessive hose string expansion or contraction, etc.) that can lead to leakage. In general, supervisory control systems provide pressure measurement, volume comparison, flow rate comparisons and detection of flow rate deviations. These methods typically detect only very large leaks or catastrophic failures. Supplementary methods, such as mathematical modeling, can be adpated to existing OTS supervisory control systems to provide more sensitive leak detection. OTS control system inspection methods in current use and supplementary methods are described briefly in the subsections that follow.

B.7.1(a) Pressure Static*

Principle of Operation

This inspection method is used to inspect for OTS line integrity. The pipeline is operated in an intermittent manner at nominal operating pressure. Static pressure measuring techniques are used to detect a leak when sections of the line are closed off. If the pressure holds, the line is considered tight. High accuracy pressure gages are used to monitor the line pressure. High leakage rates (i.e., greater than 500 l/hr) can be detected over short time intervals (about 15 minutes) by measuring the static pressure drop. Inspection for lower leakage rates requires that such effects as that caused by a non-equilibrium temperature be accounted for or eliminated.

Capability

This inspection method can be used for most of the major OTS components such as the pipelines, hose strings and the PLEM and other SPM piping. Static pressure tests, for inspection of the integrity of the OTS system, commonly are carried out on a weekly basis or before each ship offloading (at the maximum discharge pressure of the VLCC) when the DWP is used infrequently.

Advantages

This is a commonly used inspection method and is low cost, simple to implement and capable of good incipient failure detection.

Disadvantages

Some of the main disadvantages and limitations are:

(1) Requires leak detection method if leaks are located
(2) Variations in temperature, hose string movements, etc. limit sensitivity of leak inspection
(3) Difficult to detect slow leaks
Less sensitive than hydrostatic pressure difference method

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* See also Section B.3.3 - Hydrostatic Pressure Drop.

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B.7.1(b) Pressure Deviation - Continuous

Principle of Operation

Continuous monitoring of line pressure by computer at various locations along the OTS can be carried out during offloading for leak inspections. If pressure deviations (i.e., pressure drops, etc.) are excessive and exceed a set point value, system alarms are sounded.

Capability

Excessive pressure deviation can be used as an indicator of large leaks in the hose string, SPM pipeline, and offshore or onshore pipelines. The method also can be used to inspect for hose string defects that may lead to leaks or rupture. Unusual deviations in pressure caused by changes in hose characteristics can be recorded. Computer analysis of known parameters such as fluid velocity and viscosity, hose dimensions, hose surface and binding characteristics, etc., combined with a signal enhancement technique, such as pressure smoothing, would be required.

Sensitivity

Pressure deviation is most sensitive for large leaks close to the ship discharge pumps and close to the downstream end of the pumping stations. At locations where OTS pressures are low, such as upstream of the pumps, large leaks cause a smaller pressure loss that are more difficult to detect.

Manufacturer and Costs

All necessary equipment and components are commercially available. Estimated costs for a typical system that potentially can be used for leak inspection on a CALM are given in Table 4-2 (Item 8 on page 4-20). Costs are given assuming that the system is used with a typical OTS supervisory control system. Costs for a more sensitive computerized system are also given in Table 4-2, for example, Item 9 of page 4-20.

Advantages

This is a commonly used inspection method for detecting large leaks. It is simple to implement and could provide some incipient failure detection for hose strings.

Disadvantages

It is extremely difficult to detect small leaks because of the following main problem areas that affect continuous pressure measurement inspections:

(1) Variations in input or output tank heads
(2) Changes in fluid properties
(3) Changes in temperature

B.7.1(b) (Continued)

(4) Flow variations affect line pressure drop because pressure drop varies as the flow rate squared
(5) Leaks are inadvertently compensated for by pressure control valves when a system is operating at maximum capacity under pressure control
(6) Setpoints are usually set very high to prevent false shutdowns. In these instances, only very large leaks or ruptures can be detected

Extensive research and testing may be required to enable continuous inspections for hose string defects by this method.

B.7.1(c) Volume Comparisons (Balance)

Principle of Operation

A variety of volume comparison techniques for inspection of leakage is commonly used in the pipeline oil transportation industry. The basic operation is to measure the input volume, output volume and line pack to check metered barrels into the pipeline against barrels measured out. These measurements are generally based on the following equation:

$$V_L = V_i - V_o + \Delta V_s$$

where

V_L = leak volume during time t

V_i = volume of liquid put into system during time t

V_o = volume of liquid taken out of system during time t

ΔV_s = change in volume of liquid in pipe and tanks in system

Corrected flowmeter readings are used to provide measurements of V_i and V_o at the input and output. ΔV_s is usually computer corrected for line pack effects by measurements of temperature and pressure at various locations on the pipeline.

Volumes can be measured by meters (i.e., turbine flow meters, etc.) and by tank gages. The metering system provides the required volume data with the computerized supervisory control system automatically gathering, comparing and correcting for various parameters (temperature, pressure, density of crude, etc.). Computerized control systems are used that make continuous volume comparisons over typical time intervals ranging from every four minutes (Siemens of Germany) to every one to two hours. An alarm is generated when a volume comparison difference exceeds a predetermined setpoint. Settings are made taking into account corrected volumes and system tolerances in transducers, electronics, power variations, etc.

Capability

This inspection method can be used to inspect for large leaks in a short period of time and small leaks over a long period of time in the OTS pipeline from the pumping platform to the onshore storage terminal.

Manufacturer and Costs

Volume comparison systems are commercially available from a number of manufacturers. Costs vary widely depending upon line locations and dimensions, transducers, and the required accuracy and automation. Typical manufacturers of systems (Adec, Daniel, Siemens, Waugh, etc.) and flow transducers are given in Appendix A.1.

B.7.1(c) (Continued)

Advantages

Inspections can be made on an almost continuous basis during offloading. Systems can be automated to provide simple operation. Major leaks can be detected in a short period of time.

Disadvantages

Some of the main disadvantages of this method for inspection are:

(1) Detects leaks after they occur
(2) Difficult to detect slow leaks that over a period of time may result in a major oil spill
(3) Cannot detect a catastrophic OTS failure in sufficient time to prevent a major oil spill
(4) Tendency by operators to raise set-points to reduce frequency of false alarms
(5) Detects leaks only about once per hour for most commonly used systems
(6) No incipient failure detection

B.7.2(a) Flow Rate Comparisons - Continuous

Principle of Operation

Flow rate comparison inspection detects pipeline or hose string leaks by measuring the difference in the rate of flow at two locations (i.e., between the offshore and terminal ends of the OTS pipeline). Computer systems are available that can continuously compare flow rates every few seconds and generate an alarm when deviations exceed a setpoint value (1% to 5% of normal flow rate). Alarm levels are usually set to take into account changes in pumping rate, temperature or density of the oil, etc. A variety of transducers that provide signals proportional to rate of flow are commercially available. The most commonly used types include ultrasonic, turbine and orifice plate transducers.

Capability

This inspection method is generally used to inspect for large leaks in the OTS pipeline from the pumping platform to the storage terminals. However, the method also can be used for the hose strings and SPM pipelines. The method generally works best on lines where the flow is relatively stable.

Manufacture and Costs

Flow rate comparison systems are commercially available from a number of manufacturers. Costs vary widely depending upon line location and dimensions, transducers and the required accuracy and automation. Typical manufacturers of systems (Daniel Industries; Adec, Inc., Waugh Controls, etc.) and flow transducers are given in Appendix A.1.

Advantages

This inspection method is widely used and provides rapid detection of large leaks.

Disadvantages

The method can only be used to detect major oil leaks. Also, there is a tendency by operators to raise setpoints to reduce false alarms and thus decrease leak sensitivity.

B.7.2(b) Flow Rate Deviation - Continuous

This method provides continuous inspection of the pipeline or hose string leaks by measuring the deviations in flow rates at specific flow stations. If the change in flow rate exceeds a certain value (for example unexplained changes of normal flow rate of 1 to 5%, a leak alarm is sounded.

This inspection method is similar to the flow rate comparison method (Section B.7.2(a)) except that comparison with the flow rate at another location is not required.

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B.7.3 Mathematical Modeling - Continuous = 0.1% Accuracy

Principle of Operation

Mathematical modeling is a real-time, computerized monitor of the pipeline and hose string for detection of small amounts of oil leakage. Only losses in the system inventory are determined; the inspection is a form of dynamic inventorying of the pipeline product. The method consists of a mathematical model based on the momentum and continuity equations for a specified pipeline and/or hose string network. These equations are solved by iterative methods with suitable techniques such that the mathematical model is run in real time and can be trimmed as required to fit the actual pipeline. Mathematical models are available that fit the pipeline during start-up and compensates for transients such as pump start-up, shut-down, valve closures, water-hammer effects, etc. that normally occur in the pipeline. In addition, models can provide accurate means of compensating for line pack due to product compressibility, and pipe-wall and hose-wall deformations.

Modeling methods require that a significant amount of information be known and a variety of measurements be made continuously. These include product information (density, viscosity, etc.); pipeline and hose string dimensions and materials; valving, and product propagation information (flow and pressure at both ends of pipeline and/or hose string, temperature gradient of the product, etc.).

Capability

Mathematical modeling can be used for leak inspection of the hose string, SPM pipeline and platform-to-shore pipelines. The method can be used during offloading, not-offloading and static or hydrostatic leak tests.

Sensitivity

Estimated sensitivity is about 0.1% of the flow rate at the time the leak occurs. For example, if 100,000 barrels per hour is offloaded, a 100 barrel per hour leak can be detected.

Manufacturer and Costs

Mathematical modeling systems for leak detection inspection are commercially available from companies such as Bethany International, Inc. Such systems are in current use on some oil pipelines. Typical estimated cost for inspection of the CALM SPM hose strings is given in Table 4-2 (Item 9 of page 4-20) and in Table 4-5 (Item 11 of page 4-45) for the undersea pipeline.

Advantages

Some of the main advantages of this inspection method are:

(1) Computerized reduction
(2) Some incipient failure detection
(3) Provides leak detection improvements over conventional hydrostatic pressure tests

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B.7.3 (Continued)

(4) Can be used in conjunction with supervisory control systems
(5) Requires only repeatable rather than high accuracy flow meters
(6) Commercially available
(7) Continuous inspection

Disadvantages and Limitation

This method, although automatic, may require trained personnel to properly interpret results and to maintain the system.

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B.7.4 Negative Surge (Leak Pressure Wave Detection) - Continuous

Principle of Operation

A large pipeline leak that occurs spontaneously (rupture) generates a negative surge (a negative pressure wave) which propagates upstream and downstream at a speed equal to the sound speed of oil ($\approx$ 3300 ft/sec). Differential pressure transducers, installed at various locations along a line, detect the arrival of the negative surge. Since the speed of propagation and the wave arrival times at the transducers are known, a leak can be detected and located.

Capability

This method would be useful primarily for continuous inspection for large leaks in the OTS pipeline from the pumping platform to the onshore storage terminal.

Sensitivity

Negative surge systems potentially are capable of detecting (within a few seconds) leak rates greater than approximately 600 barrles per hour with a location accuracy of approximately 2 miles.

Manufacturer and Costs

A negative surge system that includes transducers, signal processor and supervisory control system is available from Siemens Aktiengesellschaft in Germany. The system has been installed and is in operation on the Rotterdam-Rhine pipeline in Germany.

Advantages

This inspection method can detect and locate almost instantaneously a large pipeline leak and can be used advantageously to supplement other more commonly used (see Section B.7.2) leak inspection or detection systems.

Disadvantages

Negative surges caused by other pipeline operations, such as pump start or stop and valve closures, must be accounted for in the control system.

B.8 SPECIAL METHODS

Inspection methods described in this section are special non-destructive types that are not commonly used in industry but can be used advantageously for inspection of many critical OTS components. Generally, most of these methods are used for continuous inspections whereas the non-destructive inspections described in section B.5 are only used periodically.

A list of inspection methods that are discussed in the following subsections are:

(1) Passive acoustic array for inspection of leaks, acoustic emissions and machinery damage;

(2) Mooring load monitoring systems;

(3) Laser inspections for underwater and above-water use;

(4) Electromagnetic reflection inspection using a special shroud and coaxial cable;

(5) Double walled pipe, pipeline and hose;

(6) External loading;

(7) Thermistor, joint-type and capacitor-type seal leak detectors;

(8) Liquid level;

(9) Continuous thermistor.

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B.8.1 Passive Acoustic Array - Leaks

Principle of Operation

Passive acoustic array inspection for leaks is based on the fact that the energy release from a leak causes continuous, characteristic acoustic waves to be generated at the leak source. These waves propagate away from the leak source and along the OTS component (hose, pipeline, etc.). An array of acoustic transducers, permanently or semi-permanently installed directly on the OTS component, detects the acoustic waves and converts them into usable electrical signals. Using known wave attenuation characteristics of the OTS components and also using suitable signal enhancement and processing techniques of the electrical transducer signals, leak location and leakage rate can be determined.

Capability

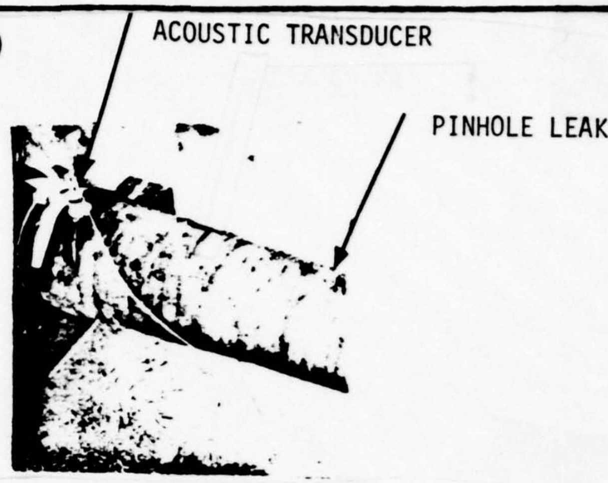
Passive acoustic array inspection for leaks is highly cost-effective for reducing oil spill risks by continuously monitoring OTS pipelines and hose strings. The method can also be used for monitoring leaks from other OTS components such as pressurized tanks, PLEM chamber, PLEM piping, etc. In these other inspections, the method may provide effective leak detection but would not be cost-effective because the existing oil spill risks are typically very low; thus the oil spill risk could not be reduced significantly. In isolated cases, however, where a leakage problem exists, the acoustic array should be considered.

An example of acoustic leak detection capabilities for a deepwater port hose is shown in Figure B-1 for a typical hose test by Science Applications, Inc., personnel. A pinhole leak (at approximately 20 psi) in a small diameter DWP submarine hose is shown in Figure B-1(a). Also shown is a typical acoustic transducer. Figure B-1(b) shows the spectrum plot of amplitude and frequency of the acoustic transducer output signal for this leak. Peak background noise is identified in Figure B-1(b) for the condition when the hose leak was sealed off. Note the large amplitude difference between leak signal and background noise. Figure B-1(c) shows the transducer output for a leak with water flowing through the hose. Note that the amplitude of the leak signal is much higher than for flow through the hose with no leak.

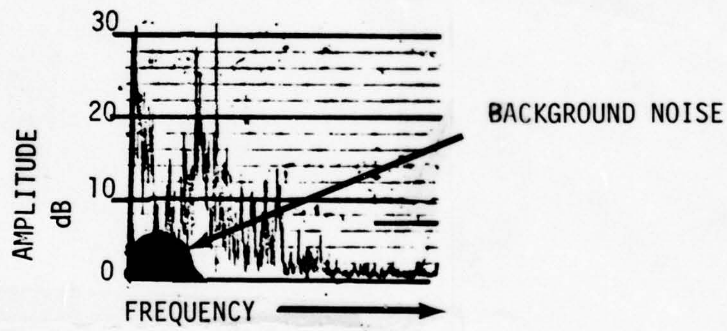
An acoustic system for the hose string would require an array of transducers installed at various locations on the hose string. Acoustic transducer signals would be continuously monitored and an alarm sounded when leakage occurs. System electronics (amplifier, signal enhancement) electronics, data processor, chart recorder, etc.) would be installed on the buoy. Data typically would be transmitted to the ship, pumping platform and onshore in a manner similar to the commercially available mooring load monitor system (see B.8.4).

Implementation of an acoustic array leak detection system (see also B.8.2) is expected to be more cost-effective and provide more effective incipient failure detection than improvements in periodic onshore inspection techniques for hoses.

B.8.1 (Continued)



(a) DWP SUBMARINE HOSE WITH PINHOLE AND ACOUSTIC TRANSDUCER



(b) AMPLITUDE AND FREQUENCY SPECTRUM OF PINHOLE LEAK

AMBINET - NO FLOW NO LEAK

FLOW THROUGH HOSE

FLOW THROUGH HOSE AND THROUGH ≈ 0.5-INCH DIAMETER LEAK

(c) CONTINUOUS SIGNAL DURING FLOW TESTS WITH/WITHOUT SMALL LEAK

Figure B-1 ACOUSTIC SIGNALS FOR LEAKS IN DWP SUBMARINE HOSE

B.8.1 (Continued)

Sensitivity

Leak rate detection and resolution of leak location depend upon a variety of factors such as OTS component material, size and length, environmental conditions and background noise, acoustic transducer spacing, design and signal enhancement techniques. Hydrostatic tests can be carried out to detect and locate small leaks that may not occur or be detectable at normal operating pressure and flow conditions.

Experimental results indicate that transducer spacings of 1000 feet or more can potentially be used on pipeline and minor leaks located within about one percent of the transducer spacing. Hose ruptures can be detected easily and hose leaks of a few barrels per hour potentially can be detected.

Manufacturer and Costs

No commercial acoustic array leak detection system is currently permanently installed on an operation pipeline or DWP hose string. However, this inspection method is being evaluated wiht other methods in a "Petroleum Leak Detection Study" for the Environmental Protection Agency. Although a continuous monitoring acoustic array system for hose strings has been developed and successfully tested by personnel at Science Applications, Inc., it is has not been tested in the DWP environment. Estimated costs for acoustic array systems are given in Tables 4-2, 4-5 and 4-9.

Advantages

Some of the main advantages of this inspection method are:

(1) Simple
(2) Excellent incipient failure detection
(3) Requires little or no interpretation
(4) Computerized, automated system can be adapted to existing OTS control system
(5) Can be used underwater,
(6) Can be used during normal OTS operations
(7) Permanent records
(8) Continuous monitoring

Disadvantages

This inspection method is of medium cost and is currently in the testing and engineering phase. System effectiveness and performance specifications are uncertain; environmental and operational tests must be carried out before installation for operational use at a DWP.

B.8.2 Passive Acoustic Array - Acoustic Emission

Principle of Operation

Experimental results have shown that acoustic signals, generated in an OTS component from external impacts, excessive internal stresses, material defects and damage, accompany internal stresses just before a leak or material failure. Each event produces a characteristic signal that can be differentiated from the other. These acoustic signals are commonly called "acoustic emissions" and are excellent indicators of incipient failure. Generally, these acoustic emissions, except for external impacts, are repetitive. Repetition rate usually increases to a peak value, drops off slightly, and the increases dramatically just before a critical material failure or leak occurs. The acoustic emissions occur only when the OTS component is stressed - externally loaded or pressurized. Acoustic emission signals are complex, dependent on structure and fault type and the frequency typically extends to the megahertz range.

The same acoustic system (see B.8.1) that is used for leaks, with additions to the signal processor, can be used to detect the acoustic emission signals. Acoustic transducers convert the waves into electrical signals. Using known wave attenuation characteristics of the OTS components and also suitable signal enhancement, counting and processing techniques, the location and condition of the flawed area can be determined.

Capability

Passive acoustic array inspections using acoustic emissions can be applied to effectively reduce oil spill risks by continuously monitoring hose strings, mooring line and pipelines. The method can also be used for monitoring leaks from other OTS components such as pressurized tanks, PLEM chamber, PLEM piping, pumping platform support structure, etc. In these latter cases, the method may provide effective incipient failure detection but would not be cost-effective because existing oil spill risks are typically very low; thus, the oil spill risk could not be reduced significantly. In isolated cases, however, when a potential leakage or structural failure problem exists, the acoustic array should be considered.

B.8.2 (Continued)

An acoustic system on the hose string, for example, would normally include both leak detection capabilities as described in B.8.1 and acoustic emission failure detection.
An array of acoustic transducers would be installed at various locations on the hose string. Acoustic transducer signals would be monitored continuously and an alarm sounded when either leakage occurs or acoustic emission rates become excessive. System electronics (amplifiers, signal enhancement electronics, data processor, recorder, alarms, etc.) would be installed on the buoy. Data typically would be transmitted to the ship, pumping platform and onshore in a manner similar to the commercially available mooring load monitor system (see B.8.4). A microprocessor or minicomputer would be used on the pumping platform or onshore to automatically store data and would be programmed to sound an alarm for excessive acoustic emission rates. System would provide detection and location of leakage and flawed or damaged areas.

A similar type acoustic system, except that leakage would not be monitored, could be used for the mooring line or pumping platform structure. In the case of the mooring line, the system would be used in the following ways: 1) detect ship breakout; 2) provide incipient failure detection of the mooring line by detecting when the mooring line is approaching an unsafe condition. The unsafe condition is detected when the acoustic emission rate reaches an unsafe level, which would have to be predetermined in the laboratory on a sufficient number of representative samples; 3) provide incipient failure detection of the mooring line by monitoring historical acoustic emission data external losses. External loading calibrations, using an increased loading schedule or possibly a weekly schedule, are highly desirable. Calibrations would be computerized to reduce costs and reduce interpretation of the mooring line condition by operating personnel. The main problem with this inspection method is that although incipient failure acoustic emission profiles prior to ship breakout would follow normal incipient failure profiles, some interpretation is required concerning

B.8.2 (Continued)

the amount of time before failure occurs. Nevertheless, there would be sufficient time to detect a catastrophic failure and stop unloading. This inspection method also is capable of providing the location of the specific areas where defects are appearing.

Sensitivity

Defect location depends upon a variety of factors such as OTS component material, size and length, acoustic transducer spacing, design and signal processing techniques. Hydrostatic tests can be used to enhance the defect so that it can be detected, whereas it might not be detected at normal operating and flow conditions.

Manufacturer and Costs

Acoustic emission monitoring systems have not been applied to mooring lines but have been used successfully in similar types of applications (i.e., Reference 45). These systems currently are being tested on offshore platforms in Europe to detect and locate crack extensions due to fatigue. An acoustic emission monitoring system has been developed and successfully tested on hose sections by personnel at Science Applications, Inc., but it has not been tested in the DWP environment.

Estimated costs for acoustic array systems are given in Table 4-2, 4-5 and 4-9 for various OTS components.

Advantages

Some of the main advantages of this inspection method are:

(1) Excellent incipient failure detection
(2) Computerized automatic system can be adopted to existing OTS control
(3) Commercial system for periodic proof testing of tanks, pressure vessels, etc. are available
(4) Can be used underwater
(5) Can be used during normal OTS operations
(6) Permanent records
(7) Can be used in all weather and darkness
(8) Continuous monitoring

Disadvantages

The main disadvantage of acoustic emission inspection is that incipient failure data are subject to interpretation as to the severity of the defect and are the length of time the defect grows to a critical size and then causes leakage or rupture.

B.8.2 (Continued)

(This inspection does provide defect location for further inspection by other means.) The method also is of medium cost. Finally, system effectiveness and performance specifications are uncertain; environmental and operational tests must be carried out for hose string and mooring system applications before installation and operational use at a DWP. See Section 5.3 for recommendations for further development.

B.8.3 Passive Acoustic and Miscellaneous Methods - Machinery Internal Defects

Principle of Operation

Acoustic transducers or, in some cases accelerometers, strain gages, or vibration transducers are hand held or permanently installed on machinery. These transducers detect the abnormal acoustical or vibrational stresses that begin when internal defects, such as bearing damage, start to occur in machinery. These transducers are usually monitored continuously and a variety of signal enhancement techniques are used to discriminate the internal damage from background noise of the machinery or external noise sources.

Capability

For inspection of most DWP machinery, the method provides for good incipient failure detection so that internal defects can be repaired before the machinery undergoes excessive damage or fails. Defects such as bearing or valve damage can easily be detected.

Sensitivity

This inspection method gives a good indication of impending machinery failure but does not provide an exact quantitative value.

Manufacturer and Costs

Inspection systems that are continuous or periodic are commercially available from a number of companies. (see Appendix A).

Advantages

A few advantages of this inspection method are:

(1) Commercial system available
(2) Good incipient failure detection
(3) Reduces machinery maintenance cost
(4) Permanent record
(5) Continuous monitoring

Disadvantages

Data are subject to interpretation as to the severity of the internal defect, but the existing system generally gives adequate warning before an internal defect causes excessive damage or failure of machinery. Although the inspection method generally reduces machinery maintenance costs, it is not cost-effective in reducing the oil spill risks. This is because the oil spill risk from machinery failure is already extremely low.

B.8.4 Strain Gage Load Sensor - Mooring Load Monitor

Principle of Operation

Strain gage load sensors or other similar types of load sensors (Piezo electric, Piezo-resistive) can be used advantageously to inspect periodically or continuously for excessive loading of many OTS components. A good example of this method that also illustrates the principal of operation is given in the following paragraph.

The most effective load sensor inspection system for a deepwater port are those that are installed to monitor mooring loads at the buoy of a SPM. The buoy is fitted with a load cell, an inclinometer (if a SALM SPM is used), a signal conditioning unit, telemetry transmittor and a power supply. The load cell, which produces an electrical signal proportional to an applied load, is used to monitor mooring line loads at the SPM. Two of the load cell arrangements that can be used are in-line tensile stress type and a shear pin type. In the case of a SALM SPM buoy heel information is obtained using an inclinometer. The signal conditioning unit processes the input signal from the load cell and inclinometer. The conditioned signal is then transmitted to the ship and/or pumping platform where the signal is decoded and load and heel angle (SALM only) are displayed and recorded. Alarm signals for excessive loadings and ship breakout can be generated at the SPM buoy, ship, pumping platform and onshore.

Capability

Strain gage load sensors are used primarily for monitoring mooring system loads at the SPM buoy. For this application three main capabilities exist:

(1) Ship breakout can be detected instantaneously and alarm sounded

(2) Provides incipient failure detection by giving and alarm when tanker loads reach an unsafe level

(3) Provides incipient failure detection by monitoring historical data on hawser fatigue

Also, monthly or bimonthly calibration of the load monitor inspection system and mooring line using a scheduled loading sequence (similar to what is done in wind tunnels, for example) is desirable. This would provide load history calibrations of the mooring line that could be used to aid in the interpretation of the mooring line condition. Calibrations can be computerized at a nominal cost; this would significantly reduce interpretations of mooring line condition by operating personnel.

B.8.4 (Continued)

Load monitoring can also be used on other OTS components such as the hose string end flange, excessive loadings at high load sections of the hose string and improper loads at the hose arm. In addition, the telemetry and data acquisition system used with the inspection method can accommodate other continuously monitoring inspection methods or sensors such as an acoustic array, and pressure and flow sensors that may be used at or near the SPM buoy.

Sensitivity

It is estimated that the system for mooring load monitoring has an accuracy of about 5 percent. Periodic external loading calibrations with computerized would improve the system accuracy and system effectiveness.

Manufacture and Cost

These types of inspection systems or load monitoring are commercially available from Ocean Technical Services, Ltd. and SBM of America. Cost of a typical system for one SPM is slightly under $100,000. Estimated yearly costs for a hypothetical deepwater port is given in Table 4.3.

Advantages

Some of the main advantages of the strain gage mooring load monitoring system are:

(1) Excellent incipient failure detection
(2) Highly cost-effective
(3) Provides permanent records
(4) Provides history of mooring loads
(5) Continuous monitoring
(6) Unaffected by environment
(7) Detects ship breakout
(8) Typical data system on SPM buoy can accommodate other inspection equipment

Disadvantages

This inspection method is of medium cost and requires some personnel training. Also, performance and reliability at deepwater ports is uncertain.

B.8.5(a) Laser Detection - Underwater

Principle of Operation

A laser system is mounted along an underwater pipeline or other OTS component. A continuous laser beam is aimed along the pipeline to a detector mounted further away. Light transmittance would decrease with escaping oil. Thus a leak can be detected.

Capability

Inspection of OTS components such as undersea pipeline, hose string, SALM SPM, CALM underbuoy hoses, etc. provides some incipient failure detection; minute leaks that can lead to an oil spill potentially can be detected before an oil spill incident occurs.

Sensitivity

Sensitivity depends on a number of factors such as laser source, laser power and detector spacing. It is expected that very small oil spills or minute leaks can be detected.

Manufacturer and Costs

This inspection is in the feasibility stage of development. However, it has been used successfully for fog and smog measurements.

Advantages

This inspection method would be continuous monitoring and would provide some incipient failure detection.

Disadvantages and Limitations

This inspection method has a number of disadvantages and limitations. Some of these are:

(1) Feasibility stage for underwater
(2) High cost
(3) Environmentl that the equipment is subjected to makes practical application difficult at best
(4) Detects a leak only after it occurs
(5) Requires highly trained personnel
(6) Many of the components proposed for monitoring by a laser are not straight. Hence, inspection may not be practical even it successfully developed beyond the feasibility stage.

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B.8.5(b) Laser Detection - Above Water

Principle of Operation

Laser detection is an inspection method which can only be applied after a leak has occurred. The laser would be placed on a high point on the pumping platform which could oversee the SPM buoy, hoses, and other DWP components. A periodic traverse in a fixed plane from shore to terminal along the pipeline and hose string would be used in measuring the laser beam absorbed at the water surface. By choosing a wave length which is readily absorbed by oil, extremely small amounts of oil can be detected.

Capability

Inspection of oil leaks from OTS pipelines, pumping platform, SPM, and hose string.

Sensitivity

Minor or medium oil spills

Manufacturer and Costs

Laser inspection systems have been successfully tested for remote sensing systems of oil leaks on water. No tests have been carried out for DWP application and environment. Costs of a system are expected to be high. Trained personnel may be required to operate and/or maintain the system.

Advantages

Continuous monitoring for minor or medium oil spills around pumping platform, particularly in location where undersea piping connects to pumping platform.

Disadvantages

Some of the main disadvantages are:

(1) High cost
(2) Requires trained personnel
(3) Affected by bad weather
(4) Detects leaks only after they occur and oil rises to the surface and in the Laser's beam.
(5) Developmental/engineering stage for DWP usage
(6) Requires very high platform to scan water around SPMs. In additions, atmospheric condition would prevent system from functioning effectively, if at all.

B.8.6 Shroud with Electromagnetic Pulsed (EMP) Coaxial Cable

Principle of Operation

This inspection method can be used continuously to detect and locate leaks using an electromagnetic pulse reflection technique with a special coaxial cable and shroud positioned above the OTS components. The coaxial cable would have breaks in the outer conductor which would be bridged electrically by salt water. A pulse sent down the cable would pass through the entire length and, depending on electrical termination, be reflected back to the sending end. If, however, a leak should develop in the pipeline, the petroleum product could be collected in a suitable shroud enclosing the cable break. When the insulating fluid would displace the conductive sea water, the cable would be electrically opened at that point. A pulse sent down the cable would then be reflected at the break pinpointing the leakage site. A typical system would include a short circuit termination of the cable that would cause an inverted pulse to be reflected back to the sending end. The inverted pulse would establish the integrity of the cable; a non-inverted reflection would indicate oil leakage.

Capability

Continuous inspection for small amounts of oil leakage from OTS components such as undersea pipeline, underground pipeline, SALM SPM, CALM underbuoy hoses, etc. provides good detection of incipient failures, minute leaks that can lead to an oil spill can be detected and located before an oil spill incident occurs.

Sensitivity

Minute oil leaks can be detected and then located within a few feet.

Manufacturer and Costs

This inspection method has been successfully tested under laboratory conditions. Typical system costs for typical DWP hose strings are expected to range from $100,000 to $150,000. Estimated costs of typical systems for various OTS components are included in Tables 4-2, 4-5 and 4-9.

Advantages

Some of the main advantages are:

(1) The inspection technique is simple to understand and operate
(2) Continuous inspections
(3) Good incipient failure detection
(4) Can be incorporated into OTS control and monitoring system

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B.8.6 (Continued)

Disadvantages

The shroud and pulsed coaxial cable may be difficult to maintain because of potential damage from marine growth, corrosion, debris, damage from external impacts, hose string movement, etc. Thus, system effectiveness is undertain and actual DWP tests must be carried out before such a system is implemented for actual use. Also, the method is expected to be of medium cost and detects leaks only after they occur.

B.8.7 Double Walled Pipe

Principle of Operation

Double walled pipe inspection method requires the use of a double walled pipe with the one transferring the fluid to be centered inside the other. A variety of oil detectors is suitable to detect and locate leaks from the inner pipe. Detectors would be located at the top and bottom of the large pipe.

Capability

All OTS pipelines and piping.

Sensitivity

Potentially more sensitive than any other inspection method.

Manufacturer and Costs

Installation of a double walled pipe inspection system is very expensive and complicated for long pipeline. The method is of low cost and cost-effectiveness for short lengths of pipe.

Advantages

The method provides continuous inspection and excellent incipient failure detection. It can be cost-effective for short lengths of piping at potential leak areas. Additionally, the double walled pipe provides a system to contain leaked oil.

Disadvantages

A double walled pipe inspection system is very costly for long pipelines and has not been used.

B.8.8 Double Walled Hose

Principle of Operation

Double walled hose inspection requires the use of a double walled hose with one transferring the fluid to be centered inside the other. Leaks from the inner hose cause the outer more elastic hose wall to expand and bulge. Visual inspection of the hose is sufficient to detect the bulge in a hose caused by an oil or water leak.

Capability

Potentially can be used for all SPM floating or underwater hoses.

Sensitivity

Sensitive enough to inspect for leakage volumes of less than a few barrels.

Manufacturer and Cost

This hose is manufacturered by Dunlop and currently costs about 50% more than a standard DWP hose.

Advantages

Some of the main advantages are:
(1) Simple inspection
(2) Excellent incipient failure detection
(3) Commercially available for some sections of the hose string
(4) Contains the leaked oil thus preventing small oil spills

Disadvantages

The main disadvantage of this inspection method is that the required hose is expensive; if implemented for all the hoses on a hose string, the cost-effectiveness is quite low. Hosever, if implemented in a few critical areas, such as the first hose off the CALM buoy, where leakage from the hose string occurs the most frequently, the method may be of cost-effectiveness. The reliability is uncertain because damage to the outer cover may allow leakage rather than bulging. Also, damage to the inner hose could occur and might not be detected by visual inspection.

B.8.9 External Load

Principle of Operation

The inspection merely requires that test loadings be applied to various OTS components using ships, for example, to pull on the hawser lines or anchor chains. Visual inspections of the condition of the OTS component and/or size measurements are taken.

Capability

Checks for external damage and size measurements (lengths, diameters, chain links, etc.) of OTS components such as hawsers and anchor chains. External loading can be used in calibration inspection systems such as a mooring load monitor system or acoustic array for the mooring system.

Sensitivity

Requires visual inspection or other inspection method to detect and locate flaws.

Advantages

Some potential advantages are:

(1) Simple
(2) Some incipient failure detection
(3) Can be used to calibrate other inspection systems

Disadvantages

The method has a medium cost.

B.8.10(a) Seal Leak Detector - Thermistor Type

Principle of Operation

A small, hand-held, portable detector is placed over the area to be inspected for leakage and the OTS component pressurized with a gas. The detector device includes a flexible seal that is placed over the inspected area and a heated thermistor (within a conductivity cell) that senses the gas leaking into the sealed area. Gas passing over the thermistor will cool it and thereby cause a change in its resistance. A second thermistor is used as a reference. Both are used in a Wheatstone bridge configuration with voltage applied. Any resistance change results in a voltage change that is displayed on a hand held digital readout device. The inspection unit includes an audio output that is set to turn on at an arbitrary leak level.

Capability

Inspection of a variety of OTS components such as hose string flanges, SALM SPM fluid swirl, hoses, pipeline, etc.

Sensitivity

About 10^{-8} scc/s for nitrogen gas

Manufacturer and Cost

Experimental device that has been developed by McDonnell Douglas Corporation (Reference 33) primarily for space applications.

Advantages

This inspection method is low cost and simple to carry out. It provides good incipient failure detection because very small leaks can be detected at elevated pressures that may not be detected at normal operating conditions.

Disadvantages

Out-of-service inspections are required and the inspection device is not commercially available. Also, the inspection device has not been tested for underwater use.

B.8.10(b) Seal Leak Detector - Joint Type

Principle of Operation

The inspection method requires the use of an inspection device that is typically placed inside OTS components such as large diameter pipelines or hose strings. End element tubes, that are wrapped around a solid cylindrical fixture, are positioned on each side of the joint or area to be inspected and pressurized to provide a good seal between the end elements and the OTS component. Then the area in between the tubes is pressurized (currently to a maximum of 300 psi with a liquid and 10 psi with a gas) and this pressure is monitored with a pressure gage. Decrease in gage pressure will indicate a bad joint or leak.

Capability

This inspection method typically is used during new construction to check joint tightness of large diameter sewer pipe, storm drains, and hig pressure piping. However, under some conditions it can be used on older pipelines and piping. This method is simple to apply and potentially can be used to check leaks in joints of large pipelines and pipes (27 to 120 inches diameter) and in hose string flange connections. The device potentially could be adapted for inspections that are carried out externally on piping, pipelines, and hose strings.

Manufacturer and Costs

This inspection equipment is commercially available at low pressures from Cherne Industrial, Inc. and at high pressure to at least 300 psi from Sanderlans & Son. Costs of the inspection device are less than $5,000.

Advantages

Some of the potential advantages of this device are:

(1) Simple to use
(2) Low cost
(3) Can potentially be used to check leaks in flange seals of hose strings
(4) Commercially available
(5) Some incipient failure detection
(6) Reduces the need to pressurize lines

Disadvantages

Out-of-service inspections are required. Also, some minor development of this inspection device may be required for practical application to DWP's.

B.8.10(c) Seal Leak Detector - Capacitive Type

Principle of Operation

This inspection method requires the use of a capacitor-type detector for inspection of leaking flange seals. A variety of techniques can be used for this inspection but in general the following approach is used. A capacitive material is placed in between two externally insulated copper electrodes. Oil, air, or water leaking through the material to the outside of a flange changes the impedance and capacitance in a complex manner. The change is detected by an electronic system attached to the copper electrodes.

Capability

Primarily for inspection of leaking OTS flanges, such as those used to connect hose sections of a hose string. Inspections could be carried out continuously using an electronic system or an on a periodic schedule.

Sensitivity

Better than 10^{-3} scc/s

Manufacturer and Costs

Inspection devices are commercially available and are low cost. Others such as the ones described in Reference 36 are experimental. Suitable devices for OTS hose flanges would require some minor development costs.

Advantages

Some of the main advantages are:

(1) Simple
(2) Low cost
(3) Good incipient failure detection
(4) Commercial devices are available
(5) Continuous monitoring

Disadvantages

This inspection method requires the detector to be designed as part of the OTS component. Also, the detectors have not been tested for DWP environments.

B.8.11 Liquid Level Sensor

Principle of Operation

This inspection method requires that an inspection device be installed in the inside or on the outside of the inspected OTS component. Liquid levels can be detected by both intrusive and non-intrusive liquid level detectors. A variety of types of sensors such as ultrasonic, optical, microwave, nuclear, etc. can be used. Continuous operation is typically used and monitoring is normally done remotely and set-point alarms included.

Applications

OTS tanks, piping, dike levels, etc.

Sensitivity

Better than 1% accuracy of liquid level depth.

Manufacturer and Costs

Liquid level sensing systems are available from numerous manufacturers at costs below a few thousand dollars (see Appendix A).

Advantages

Some of the main advantages are:

(1) Simple to implement and operate
(2) Low cost
(3) Some incipient failure detection
(4) Commercially available
(5) Continuous monitoring

B.8.12 Continuous Thermistor

Principle of Operation

This inspection method requires that a thermistor sensing device be placed above and along the inspected OTS components. Oil leaks produce a marked change in the properties of the continuous thermistor type cable that is used.

Capability

Continuous detection of oil leaks in hose strings and underground and undersea pipelines.

Sensitivity

This has not been determined.

Manufacturer and Costs

The inspection device developed by Allison Control is in the feasibility-experimental stage for most DWP applications.

Advantages

The main advantage is continuous monitoring capability.

Disadvantages

The major disadvantages are:

(1) Projected medium cost

(2) Sensitivity and feasibility for use at DWPs have not been demonstrated.

B.9 MISCELLANEOUS METHODS

A variety of various types of inspection methods with somewhat limited capabilities are included in this section. Many of the methods included here are for inspection of a specific OTS component with a minimal expected reduction in the oil spill risk. Other methods are limited in use because of deepwater port environmental conditions. Finally, onshore inspections currently used for hoses are identified. These methods, on occasion could be used to inspect hose sections that are in use or that have been disconnected from the hose string.

B.9.1 Hydrocarbon Probe (Sniffer)

Principle of Operation

This inspection method utilizes a probe to detect the hydrocarbons emitted from an oil leak in an undersea pipeline. Hydrocarbon probes with associated systems are capable of continuous analysis of dissolved hydrocarbon gases, ethylene, ethane, etc. Thus, the method can be used to identify leakage from an undersea pipeline versus natural underground seeps, as distinguished by their characteristic hydrocarbon ratios. The probe is mounted in a mechanical towfish that is placed near the bottom surface and at some distance behind a pulling boat which is equipped with a winch to accomodate the twofish. The signal from the hydrocarbon probe is conditioned and then sent up the towing cable to an analyzer and recorder on the pulling boat. A pressure sensor usually is mounted in the towfish to provide depth measurement.

Capability

This inspection method provides a quick survey of the undersea pipelines for small or minor oil leaks that may not be visible on the ocean surface. It can also be used to inspect for oil that may settle on the ocean bottom from leakage of an OTS component. The device can be towed at fairly high speed (6-8 knots) and thus can be used to inspect a long section of pipeline in a single day.

Sensitivity

Analytical sensitivity typically about 5×10^{-9} ml hydrocarbon per ml water.

Manufacturer and Costs

Hydrocarbon probe systems with towfish, are commercially available, e.g., from Inter Ocean Systems, Inc. The towfish and probe costs are typically less than \$50,000. Inspection services are available at daily costs of less than \$750 (including operator).

Advantages

Some of the main advantages are:

(1) Simple
(2) Low cost
(3) Commercially available and inspection services available
(4) Good incipient failure detection
(5) Provides continuous record
(6) Fast inspection

B.9.2 Laser Holography

Principle of Operation

This inspection method can be applied to OTS components to inspect for small changes in surface characteristics of the component material under stress that may be indicative of potential failure. Laser holography systems have been in existence for at least the past ten years. However the systems still are complex and the exact mathematical analysis is beyond the scope of this report. Detailed descriptions and analysis are available in the literature. In brief, the surface to be inspected is irradiated with laser light and high resolution film is exposed by laser light reflected from surface. Developed film produces a 3 dimensional hologram. If surface undergoes a topographical change, another exposure is made on the same film and minute changes in topography can be recorded. Material changes can be detected by fringe patterns shown on holographic reconstructions.

Capability

The method can be used for inspection of defects in floating hose strings.

Sensitivity

Wave length of laser light.

Manufacturer and Costs

Laser holography systems are commercially available from a number of companies. Costs are generally quite high (greater than $100,000) and depend a great deal on the type of laser and laser reconstruction system required. In addition, installation, operation, and maintenance costs are expected to be high.

Advantages

The main advantage of this inspection method are that commercial systems are available and it provides some incipient failure detection. Also, no physical contact is required with the test specimen.

Disadvantages

A few of the main disadvantages and limitations are:

(1) Can be used for inspection of only a few OTS components
(2) Value of inspections are uncertain
(3) Medium to high cost
(4) Requires highly trained personnel
(5) Very difficult to use at sea on DWP components
(6) Vibration free environment is required

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B.9.3 Magnetic Chip

Principle of Operation

Magnetic chip detectors are installed on machinery to monitor excessive internal damage. The detectors are examined periodically on a on a regular basis.

Capability

Provides an indication of deterioration of machinery internal components and bearing damage.

Manufacturer and Costs

These inspection devices are commercially available and their cost is low.

Advantages

A few of the main advantages are:

(1) Simple
(2) Low cost
(3) Commercially available
(4) Some incipient failure detection
(5) Reduces machinery maintenance costs

Disadvantages

This inspection method is not effective in reducing oil spill risks.

B.9.4 Oil Odor

Principle of Operation

Odor of small amounts of leaking oil is detected by an inspector. Inspections are usually carried out from a small boat or launch that travels along and near the hose string and SPM.

Capability

Detection of minute amounts of oil leakage from the hose string, above the SALM SPM, and on the CALM SPM.

Sensitivity

Very minute oil leaks.

Advantages

This inspection method is very simple, can be used in darkness or bad weather, and provides good incipient failure detection.

Disadvantages

The inspection is not quantitative and is subject to personnel error. Also, wind may cause the oil odor not to be detected.

B.9.5 Other Inspection Methods with Limited DWP Application

A variety of inspection methods can be used for inspection of a few deepwater port OTS components. These are described briefly in the following subsections.

B.9.5.1 Milk Solution

Diver visual inspections for leaks in underwater OTS components can be aided by spraying the area around a component to be inspected with evaporated milk from a plastic bottle. Minute leaks cause the suspended milk solution to be blown away. This is particularly effective when the hose is pressurized and filled with water.

B.9.5.2 Leak Detection Solution

Leak detection solution is sprayed on to the inspected component. Small leaks in pressurized gas piping cause the leak solution to produce easy-to-see foam and bubbles. Various types of leak detection solution are available from a number of companies such as Circle Seal Corporation.

B.9.5.3 Thermal Paint, Liquid Crystals

These materials are applied to brazed joints, adhesive-bonded joints, metallic platings, electrical assemblies, etc. and measure lack of bond, hot spots, heat transfer and isotherms.

The method is of very low cost and is simple to apply and inspect. It can only be used on thin-walled surfaces and has a critical temperature time relationship.

B.9.5.4 Thermal or Infrared (Radiometer)

This method potentially can be applied to hose strings. Infrared can detect changes in hose exterior surface temperature caused by oil seeping into the hose structure. This occurs if the oil is at a different temperature than the hose. This inspection method can also be applied to brazed or adhesive bonded joints and metallic platings or coatings to inspect for lack of bond, hot spots, heat transfer or isotherms. The method is sensitive to temperature variations of about $1^{o}F$ and provides permanent records or thermal pictures. No contact is required and the inspection equipment is portable. The equipment is expensive and provides poor resolutions for thick specimens. Also, temperature-time relationships are critical and external environments, particularly for DWP hoses, would make quantitative inspection data extremely difficult to obtain.

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B.9.5.5 Microwave

This inspection method is high accurate for measurement of thickness and position, and can be used to detect cracks, holes, etc. in non-metallic parts. The equipment is portable. However, the method normally requires trained personnel and cannot be used to penetrate metals.

B.9.5.6 Sonic

This method can be used to inspect debonded areas or delaminations in metals and non-metals. It can be applied to metals or non-metal composites, honeycomb, plywood, etc. The method is simple and can locate far-side debonded areas. Inspection systems incorporating the method are commercially available. Surface geometry, however, may confuse inspection results.

B.9.5.7 Electrified Particle

Electrified particle inspection can be used to detect surface defects in non-conducting materials, through-to-metal pinholes on metal-backed surfaces and cracks from cycling. The method is typically applied to glass, non-homogeneous materials such as plastic coatings on rigid surfaces. The method is useful on materials not practical for penetrant inspections. However, the method has poor resolution on thin coatings and can give false indications from moisture streaks. The method is not considered suitable for most inspections of components in a marine environment, such as hoses.

B.9.5.8 Filtered Particle

The method is based on a liquid flow of filtered particles into a cracked area and the stranding of larger particles closeby. Filtered particle inspection typically is used to inspect for cracks, porosity and differential absorption. It is typically applied to porous materials such as concrete. The method can use colored or fluorescent particles and can be quickly and easily applied.

Thie method is not considered suitable for most inspections of components such as hoses in a marine environment.

B.9.5.9 <u>Onshore Hose Inspections</u>

Recommended inspections for:

- Hydrostatic tests
- Electric continuity tests
- Vacuum tests
- External inspections
- Internal inspections

See Buoy Mooring Forum Hose Guides, Reference 51.

APPENDIX C

FINAL REPORT

SYSTEM SAFETY ANALYSIS REPORT

Deepwater Port Inspection Methods and Procedures

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1.0 INTRODUCTION, SUMMARY AND CONCLUSIONS

The Deepwater Port Act of 1974 gives the Secretary of the Department of Transportation and, by delegation, the U.S. Coast Guard specific authority to regulate the design, construction and operation of deepwater ports off the coast of the United States. Some of these regulations deal with safety and the prevention of oil pollution. This study is one of several providing information for future regulations dealing with pollution. More specifically this study has the overall objectives of identifying and assessing inspection methods and procedures for the OTS (Oil Transfer System) of deepwater ports. The envisioned results will provide cost-effective means of minimizing accidents and oil spills from this system. Other concurrent programs complement this study; they deal with tankships and their movements, oil spill clean-up equipment and procedures, and the control system for the OTS.

The strategy of the study was first to identify those failures of components and subsystems of the OTS, together with the subsystems of associated structures and controls, which contribute most significantly to the risk of oil spills and which are amenable to risk reduction through inspection. Second, candidate inspection methods and procedures were selected and then ranked based on their potential for reducing risk.

This report describes the results of the first stage of the effort. It deals not only with the components of the OTS itself, but also with other elements which may directly affect the integrity of the OTS. Clearly the failure of some portion which contains oil (e.g., piping, hose, etc.) may result in an oil spill of some size. However, there are numerous other components and subsystems whose failure may eventually lead to the failure of the oil containment components. For example, these include the mooring hawsers and the pumping platform structure. Moreover, there are numerous possible direct human errors such as making a faulty hose-cargo manifold connection. Most of the OTS components can be

inspected to detect failures, and oil transfer procedures can be checked and rechecked, both to prevent pollution effectively.

The safety study utilized FMEA (failure mode and effects analysis) and fault tree analysis. These were used to develop both the frequency and causes of spills from the OTS. Concurrently, the size of the spills via the several failure modes also were estimated. Frequency and size combined as a product give a measure of risk which can be used to rank the potential pollution severity of the failures. This ranking, in turn, points up the most critical problems for which appropriate inspection techniques will be the most effective in reducing spills and adverse environmental effects.

In order to utilize FMEA and fault tree analyses successfully, it was necessary to focus on a specific system with well-defined assemblies of components and operating procedures. For this purpose a hypothetical deepwater port which is a composite of LOOP and SEADOCK was used. The port consists of six SPMs (Single Point Moorings) connected by undersea pipelines (48 to 56 inches OD) to a central pumping platform mounted on piles set in the sea floor. The pumping platform supports three pump trains (as for LOOP), together with ancillary strainers, air eliminators, a custodial metering complex, and oily water waste treatment equipment. The discharge of the pumps is fed into one or more of three 48-inch OD pipelines, 43 miles long to an intermediate storage terminal ashore. The analysis considered all oil-containing piping from the cargo tanks of a moored tankship to the root valve of the pipes to the storage tanks of the onshore terminal.

It was assumed that the deepwater port would handle only tankships offloading an oil cargo. Further, it was assumed that the daily throughput for the port would be 3.4×10^6 bbls/d. On the average, 776 ship calls per year would be made, and 1.6×10^6 bbls would be discharged from each in 16 hours (1×10^5 bbls/hr pumping rate).

The analyses included the use of either a CALM (Catenary Anchor Leg Mooring) or a SALM (Single Anchor Leg Mooring) as the SPM. Designs of offshore moorings and operating procedures worldwide were reviewed.

Currently there are approximately 150 CALM SPMs in service or under construction and only 10 SALMs. Other types also are being used, including 4 Single Buoy Storage, 3 articulated mooring towers, 4 fixed tower SPMs and 4 yoke tower systems. The reason for including SALMs in the analysis was that both LOOP and SEADOCK have selected SALM units.

The analyses required the formulation of a data base for the failure rate of the several components of the OTS. For many common components such as the pumps and valves on the pumping platforms, data reported for industrial equipment were used. The frequency of occurrence of pipeline leaks and ruptures was based on data from the Office of Pipeline Safety Operations (Department of Transportation) for terrestrial pipelines. These data were corroborated by a few data on spills from undersea pipelines in the Gulf of Mexico, obtained from the U.S. Geological Survey. The U.S. Geological Survey also supplied data on spills resulting from damage to offshore platforms, such as caused by ship collisions and fires.

Failure and spill frequency for the more unique components of a deepwater port, especially the hoses, were derived from spill data for SPMs operated by a single company during the period 1960 to 1971. These data reflect the operating procedures prevalent during that time. Several oil companies and operators of SPMs have claimed that substantial changes in operating and inspection procedures have resulted in fewer problems and spills, especially for the hose strings. Nevertheless, the data were used since, first, they are the only data available, and second, they represent the spill history associated with an identifiable technology and inspection practice.

Spill data for offloading and loading tankships at more conventional shore-side terminals were reviewed. This was done to help define the failure modes which lead to oil spills during oil transfer operations.

The detailed results of the safety analysis are presented in the following three sections. Section 2.0 contains a description of deepwater ports and SPMs, and describes the components of the deepwater port analyzed. Section 3.0 contains a review of SPM operating experience,

spill data for conventional oil transfer operations and the safety analysis. The frequency and risk of spills are developed and presented. Section 4.0 describes the strategy to be used in developing inspection techniques and presents a priority ranking of the spill problems to which the inspections would apply.

The following are the principal conclusions of the safety analysis:

1. Consistent with the general impression of industry, one of the greatest risks of oil spills is comprised of leaks and ruptures of the hose strings. For the deepwater port analyzed, minor spills* from leaks may be expected 13 times per year. Ruptures of the hoses caused by, for example, the failure of the mooring hawsers, are predicted to occur less frequently, 0.6 per year, but a major spill could result.

2. A second major source of oil spill risk are the platform-to-shore and the onshore pipelines. From available data, a rupture from external damage (e.g., a dragging anchor), corrosion and defective welds is predicted to occur 0.010 per year. However, because of the large volume of the lines, a major spill could result, perhaps as much as 100,000 bbls, even if no oil were being pumped through the lines at the time.

3. Leaks from the SPM units and the SPM pipelines (SPM to platform) pose a much smaller risk of oil spills than do the hoses. The steel piping and components are much less vulnerable than hoses to fatigue and wear failures.

4. The risk of spills from the OTS components on the pumping platform and from the onshore facilities is very small. The reason is the secondary containment provided by the curbed decking on the platform and the berm dikes surrounding the facilities ashore. Inspection to insure the integrity of these containments is nearly as important as inspection of the OTS components themselves.

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*According to the National Contingency Plan:

Minor spill is $<$ 10,000 gal
Medium spill is 10,000 to 100,000 gal
Major spill is $>$ 100,000 gal

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5. The occurrence of several potentially catastrophic accidents are not significantly frequent to pose a major risk. One class of such accidents includes the corrosion of the SPM buoy and the platform supports. Evidently the reason for their infrequency are the well-developed inspection techniques for detecting excessive corrosion damage and for maintaining the effectiveness of the corrosion control systems (sacrificial anodes, cathodic protection, etc.). Recommended inspection procedures must include those procedures which are both normally practiced and are effective.

6. Two types of inspection techniques are recommended: those that reduce the frequency of spills; and those that reduce the size of a spill if a spill occurs. The former is the only type suitable for controlling the frequent incidence of small spills. The latter essentially involves continuous monitoring and is effective for infrequent, but potentially large spills.

7. The reported spill experience at SPMs (1960-1971) indicated a decreasing incidence of spills during the first few years of their operation. Subsequently the spill rate leveled off at approximately 0.02 spills per ship call. This spillage rate is not significantly different from that experienced for conventional terminals: 0.012 for U.S. ports and 0.017 to 0.013 for Milford Haven, U.K. during 1970-1973.*

8. The frequencies of spills at loading and offloading SPMs appear to be substantially the same. However, the volumes of oil spilled at the former type of port are substantially larger. A major reason for this may be a few incidents in which the ship's cargo tanks overflowed. Such accidents are a major cause of large spills at conventional U.S. terminals. Although higher pumping rates at loading ports may be a contributing factor, these accidents are the direct result of human error and are not the result of the failure of the integrity of the OTS.

* The dredged depth of most ports and U.S. ports in particular is such that vessels loaded with up to 40,000 to 60,000 tons of oil can enter. From a total oil spill risk point of view, therefore, the number of port calls at a deepwater port will be 1/3 to 1/6 (150,000 to 300,000 dwt tankers) of those at a conventional port for the same total oil transported, and hence there would be fewer spills at a deepwater port.

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DEEPWATER PORT INSPECTION METHODS AND PROCEDURES.(U)
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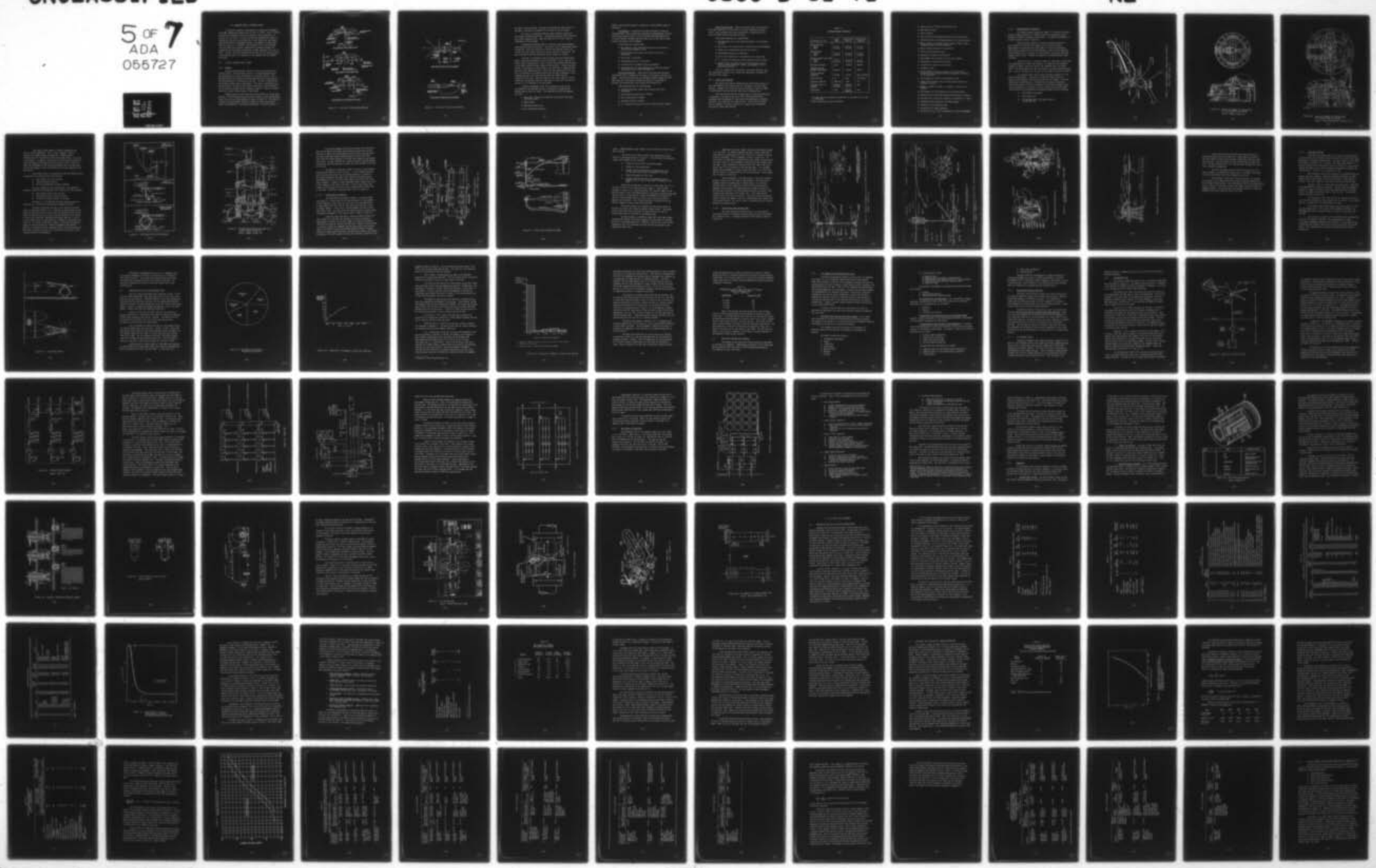

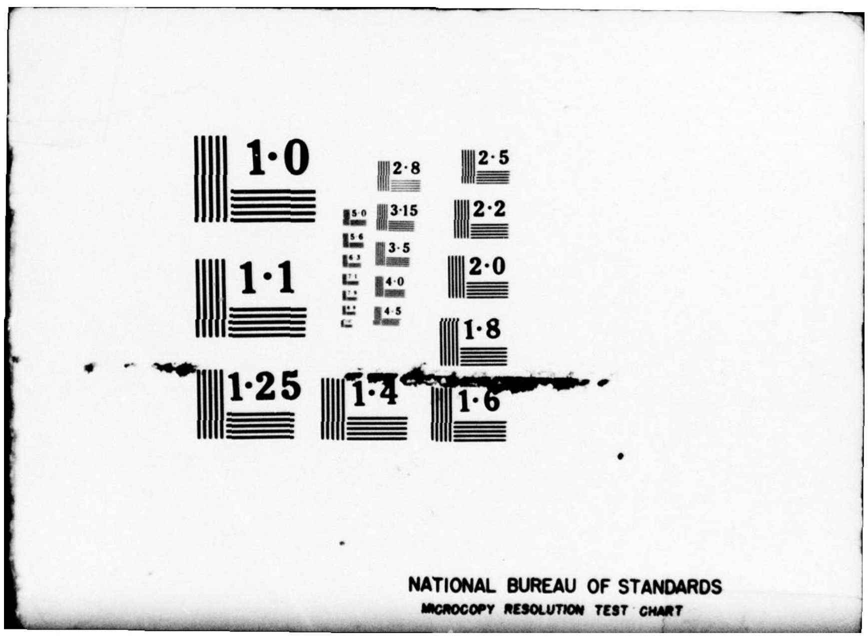
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2.0 DEEPWATER PORT OIL TRANSFER SYSTEM

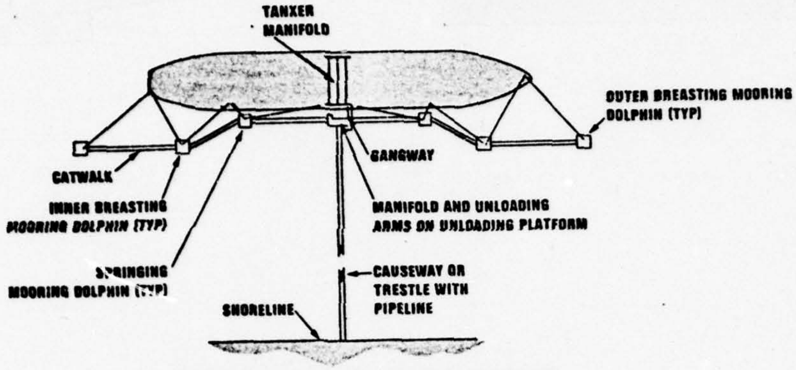
This Section contains a description of a hypothetical deepwater port (DWP) complex which might exist off the U.S. coast. The Oil Transfer System of this complex serves as the subject of the forthcoming risk analysis for oil spills. In order to place the hypothetical complex in perspective, the first two subsections of this report give some general descriptive material on Monobuoy Systems, with emphasis on those that might be used at U.S. locations, and characteristics of existing DWPs. The third subsection provides information on accepted standards and regulations for the design and operation of DWPs, especially off the U.S. coast. Finally, the fourth subsection describes the oil transfer system to be analyzed, which is a composite of the proposed LOOP and SEADOCK facilities.

2.1 TYPES OF DEEPWATER PORT SYSTEMS

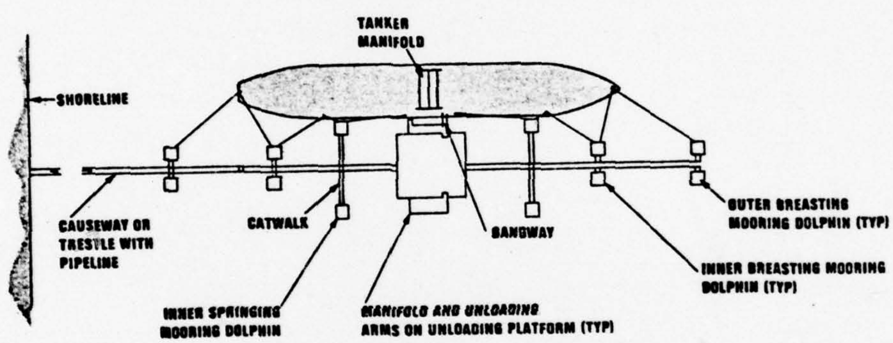
2.1.1 General

Offshore mooring systems consist of either a fixed berth or a floating berth. The fixed berth consists of a shoreside-type mooring and cargo-handling piping transferred to an offshore location. The mooring bollards are located on mooring dolphins and the fixed platform for cargo handling is constructed on pilings. The ship is moored with a set of breast hawsers and spring hawsers. The cargo is transferred to a manifold which is located on the fixed platform and is then transferred to the shoreside storage facility through a pipeline. Figure 2-1 shows a plan view of each of three types of fixed berths.

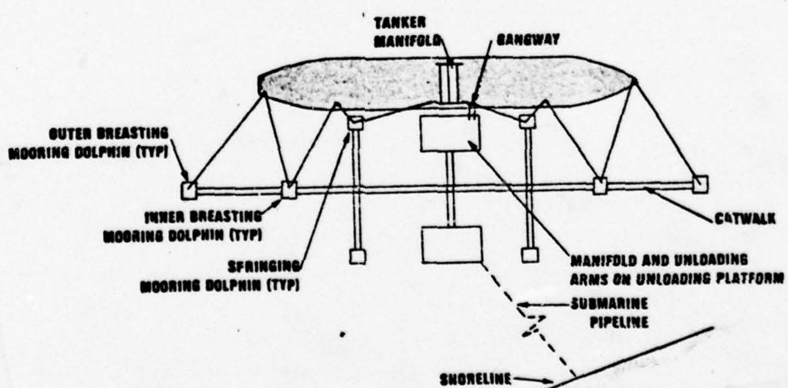
Floating berths may be either multi-buoy moorings or single point moorings. The multi-buoy mooring consists of three to seven mooring buoys. A plan view of a multi-buoy mooring is shown in Figure 2-2. The buoys are located to provide mooring support to prevent the ship from moving in either the athwartship or the forward directions. The ship's anchors



PLAN VIEW OF ONE SIDED WHARF

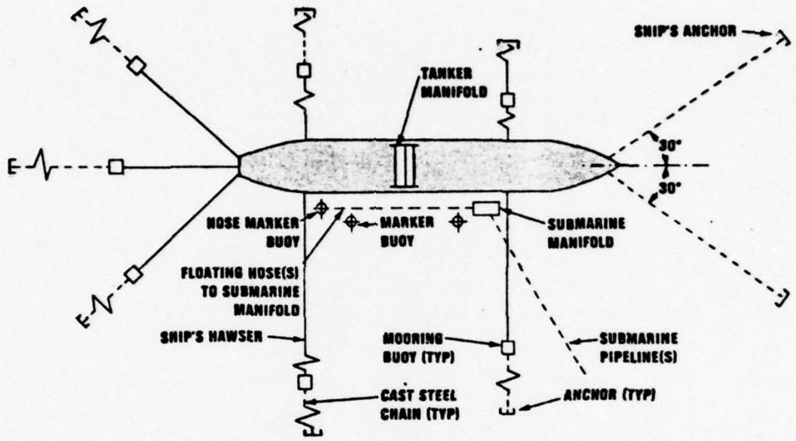


PLAN VIEW OF TWO SIDED PIER

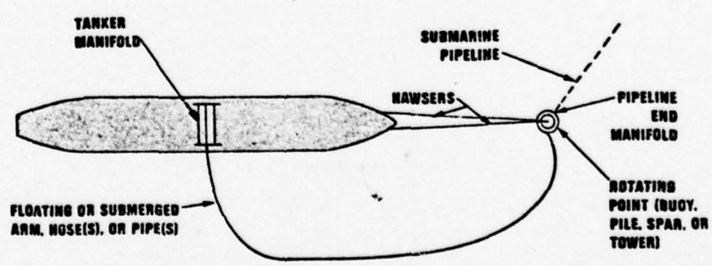


PLAN VIEW OF TWO SIDED SEA !SLAND

Figure 2.1. Plan View of Floating Buoy Moorings



PLAN VIEW OF MULTI-BUOY MOORING



PLAN VIEW OF SINGLE POINT MOORING

Figure 2-2. Plan View of Single Point Mooring

are used to secure the bow. The ship's own hawsers are used to moor to the buoys. Each buoy is connected to an anchor on the sea bottom.

The cargo is transferred from the tanker manifold through the cargo hoses to undersea pipelines. The undersea pipelines carry the cargo to a shore storage facility. When the hoses are not in use, they are submerged on the sea bottom.

A single point mooring (SPM) is a mooring system which employs a single mooring point for the ship. The ship is free to weathervane around the mooring. With the resolution of forces from the wind, waves, and current, the ship aligns itself so as to give the least resistance. The buoy is moored to the sea bottom with either anchors or pilings.

The cargo is transferred from the tanker manifold through cargo hose(s), which are configured in one of three ways. First, the hose is either rigid or attached to a rigid structure and connected from the buoy to the tanker manifold without contact with the water. Second, the hose follows a lazy pattern on the surface of the water and is connected from the buoy to the tanker manifold. And third, the surface portion of the hose is connected to the tanker manifold and the other connection is to a submerged portion of the buoy mooring below the tanker mooring connection on the buoy. When the hoses are not in use, they are either reeled onto the mooring structure, permitted to float lazily on the sea surface, or are submerged on the sea bottom.

A detailed knowledge of the site conditions and the marine environment at the proposed location is necessary to determine the optimum type of berth to install. The required site and environmental data are:

- Wind, wave, and current conditions during normal operations and during storms;
- Water depths;
- Maneuvering areas; and
- Soil and bottom conditions.

However, each berthing system is suitable for certain general types of conditions.

Fixed Berths. Fixed berths have been installed in naturally protected areas, such as Bantry Bay (Ireland) and Newfoundland (Canada); artifically protected areas, such as Rotterdam (The Netherlands) and Le Havre (France); and generally mild areas, such as Ras Tenura (Saudi Arabia) and Freeport (Grand Bahamas).

Fixed berths are suitable when:

- The location is well sheltered from waves and currents or the marine environment is mild.
- The prevailing wind, waves, and currents do not vary excessively.
- Easy access is available.
- The maneuvering area is restricted.
- A large variety of products are to be handled.
- The desired rate of cargo handling is so high that several cargo hoses must be used simultaneously.

Multi-Point Moorings. Twenty multi-point moorings have been installed in the U.S. waters off the coasts of California, Florida, and Hawaii. The multi-point mooring can withstand slightly rougher environments than the fixed berth, provided the mooring is orientated to minimize the wind and wave forces acting on the moored ship.

Multi-point moorings are suitable when:

- The prevailing wind, waves, and currents do not vary excessively.
- The available mooring area is limited.
- Quick installation is needed.
- Available funds are limited.
- It is desired to reduce the traffic density inside a harbor.

Single Point Moorings. About two hundred single point moorings have been installed or are on order for various locations around the world. These locations have varied from shallow, protected areas to areas with deep water and extreme conditions.

Single point moorings are suitable when:

- Sea conditions can be very rough and weather can be extreme at times.
- Wind, waves, and currents vary in directions up to 360 degrees.
- Tankers up to 750,000 tons dwt use the facility.
- Large maneuvering area is available.
- One to four products are to be handled at any given time.
- It is desired to reduce the traffic density inside a harbor.
- Channel widths and depths inside existing harbors are too small to permit deep draft tankers, and dredging is not a feasible alternative.

Table 2-1 compares the fixed berths, multi-point moorings, and the single point moorings; and it shows the approximate limitations on the use of each system.

2.1.2 Single Point Moorings

Any single point mooring system must be sufficiently elastic to allow the moored vessel to move under the influence of current, waves, and wind. However, the system must be stiff enough to limit the extent of these motions and the resultant forces due to these motions.

This Section describes the various types of single point moorings in operation or on order at the end of 1976, gives the particular advantages and disadvantages of each type, and summarizes the necessary criteria in the selection of a specific type. The following information is necessary to select a mooring site location and to determine the type of single point mooring:

Table 2-1

OFFSHORE MOORING COMPARISON

? Fixed Berth   Multi-point ?

Limitations on Use	Fixed Berths	Single Point Mooring	Multi-Point Mooring
While berthing			
Waves	3-4 ft	5-10 ft	5-7 ft
Wind	25 knots	26 knots	26 knots
While moored			
Waves	4-10 ft	12-16 ft*	6-10 ft
Wind	50 knots	52 knots	50 knots
While transferring cargo			
Waves	4-10 ft	12-16 ft*	6-8 ft
Wind	35 knots	35 knots	35 knots
Distance Offshore	Least	Farthest	Medium
Maneuvering and seabed requirements	Smallest	Largest	Medium
Ease in getting underway	Average	Easiest	Most difficult
Tugs required	Yes	None	Not usually
Launches required	Sometimes	Yes**	Yes
Susceptibility to damage	Moderate to high	Moderate to low	Low
Investment	High	Low to Moderate	Low

* For some specially designed installations in the North Sea, as high as 26-30 feet.

** Some installations allow self-mooring.

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- Range of sizes of ships to use the facility.
- Mean depth of water.
- Tidal variation.
- Wind (velocity and frequency pattern for each direction).
- Currents (velocity and frequency pattern for each direction).
- Waves (regular or confused pattern, height, length, slope, frequency pattern for each direction).
- Nature and configuration of the sea bed.
- Traffic pattern and sea lanes.
- Navigational aspects and constraints.
- Requirements and availability of tugs and launches.
- Requirements of other marine traffic.
- Frequency and intervals of hurricanes.
- Frequency of fog.
- Maximum number of days and length of each interval the mooring will not be operational due to weather, hurricanes, or sea conditions.
- Total quantity of cargo to be handled per year.
- Loading and discharge rates for each grade of crude oil, product, or slurry.
- Number of grades or crude oil, product, or slurry to be handled.
- Requirements for the discharge of dirty ballast water.
- Bunkering facilities either through the mooring or by barge.
- Availability of divers for inspection, maintenance, or repair.
- Requirements and availability of repair barges.
- Distance to the storage facility.
- Suitability for futher expansion.
- Availability of oil spill containment and clean-up equipment.

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2.1.2.1 Catenary Anchor Leg Mooring

The catenary anchor leg mooring (CALM) is a flexible restrained mooring system consisting of a floating cylindrical buoy moored to the seabed by a network of catenary anchor chains. The general arrangement of the CALM system is shown in Figure 2-3.

CALMs have been installed at various worldwide locations in water depths up to 300 feet and located up to 150 miles offshore. Approximately 75 percent of the total number of single point moorings installed by the end of 1976 are the CALM type. There is wide experience with the CALM, and it has proved to be sufficiently reliable to berth the longest vessels afloat. Designs for vessels up to 700,000 dwt have been installed.

The buoy itself is a central support for piping and is subdivided into compartments for safety and strength. The buoy must have adequate buoyancy to support the anchor chains, the submarine hoses, the center swivel, and the turntable with the revolving oil carriage and mooring equipment. Some of the features of the buoy are indicated in Figures 2-4A and B.

The catenary anchor chains supply the mooring support for the buoy and moored vessel. The chains are connected from the buoy to anchors on the seabed or anchor piles driven into the seabed. The anchor chains must be tensioned, set, and sufficiently long so the mooring load on the anchors or piles is tangential to the seabed, thereby lessening the tendency for the anchors or piles to break-out from the seabed. The principal factors governing the anchoring pattern are the following:

- Environmental conditions;
- Water depth; and
- The maximum size of the vessel that will use the facility.

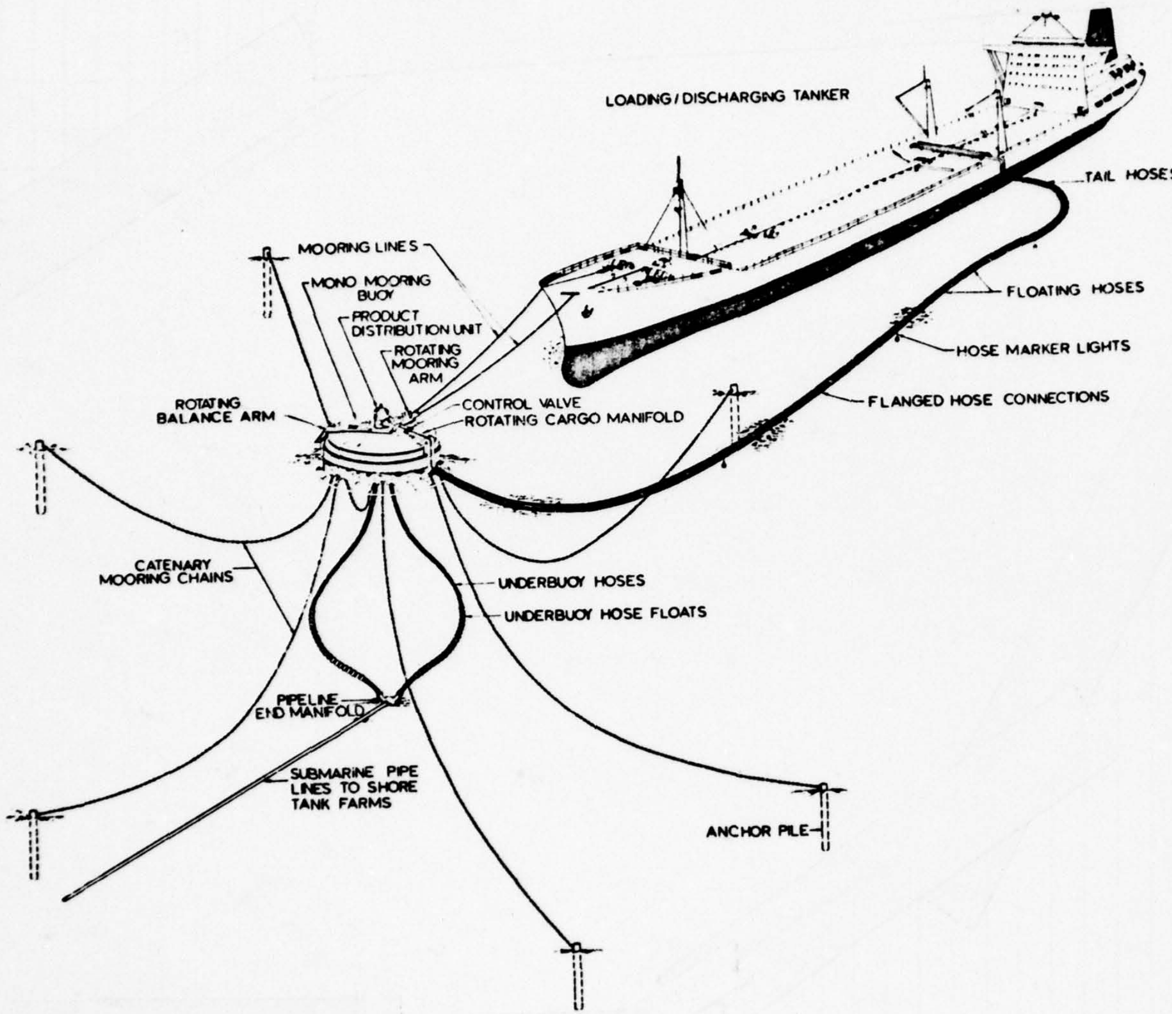

Figure 2-3. General Arrangement of Catenary Anchor Leg Mooring

Source: IMODCO, Europe, Inc.

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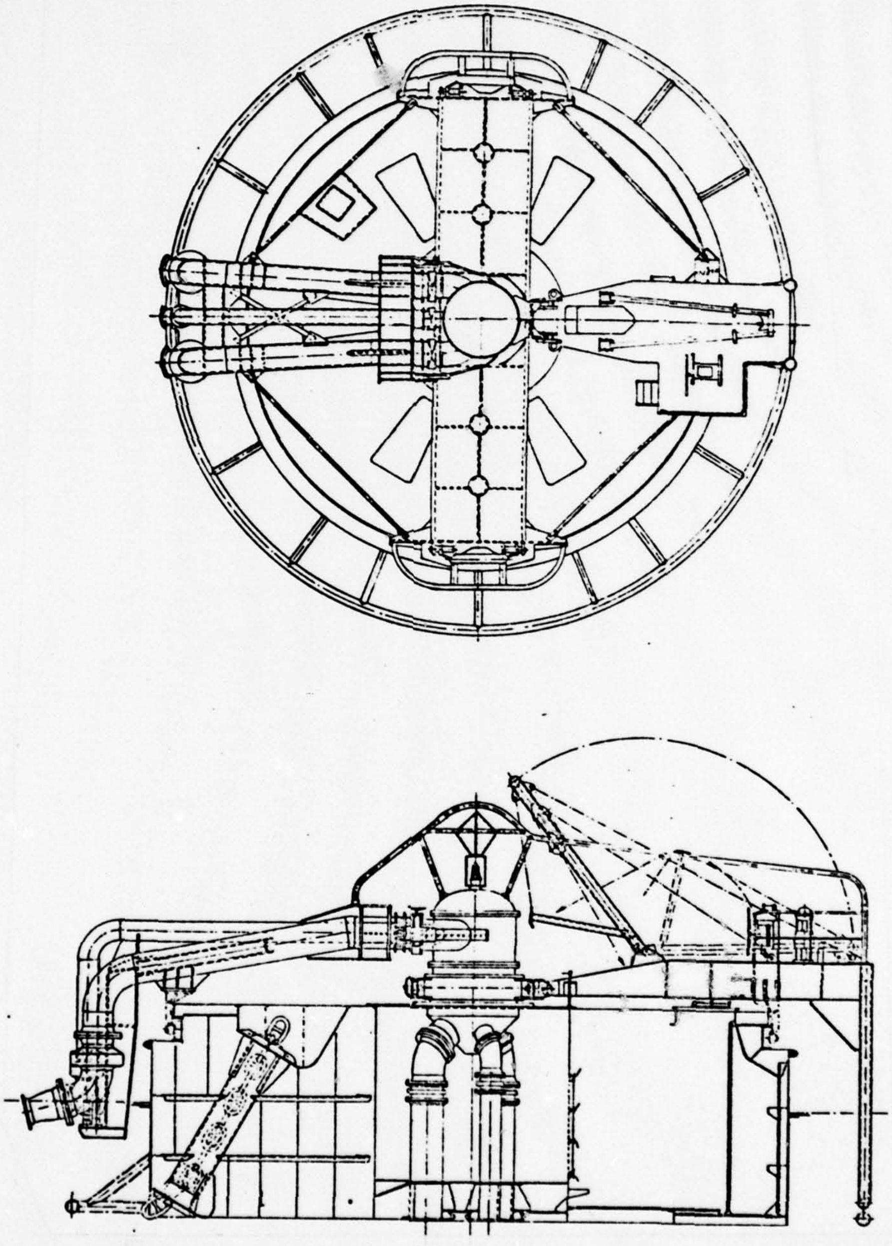

Figure 2-4A. General Arrangement of a Surface Buoy for Catenary Anchor Leg Mooring

Source: IMODCO, Europe, Inc.

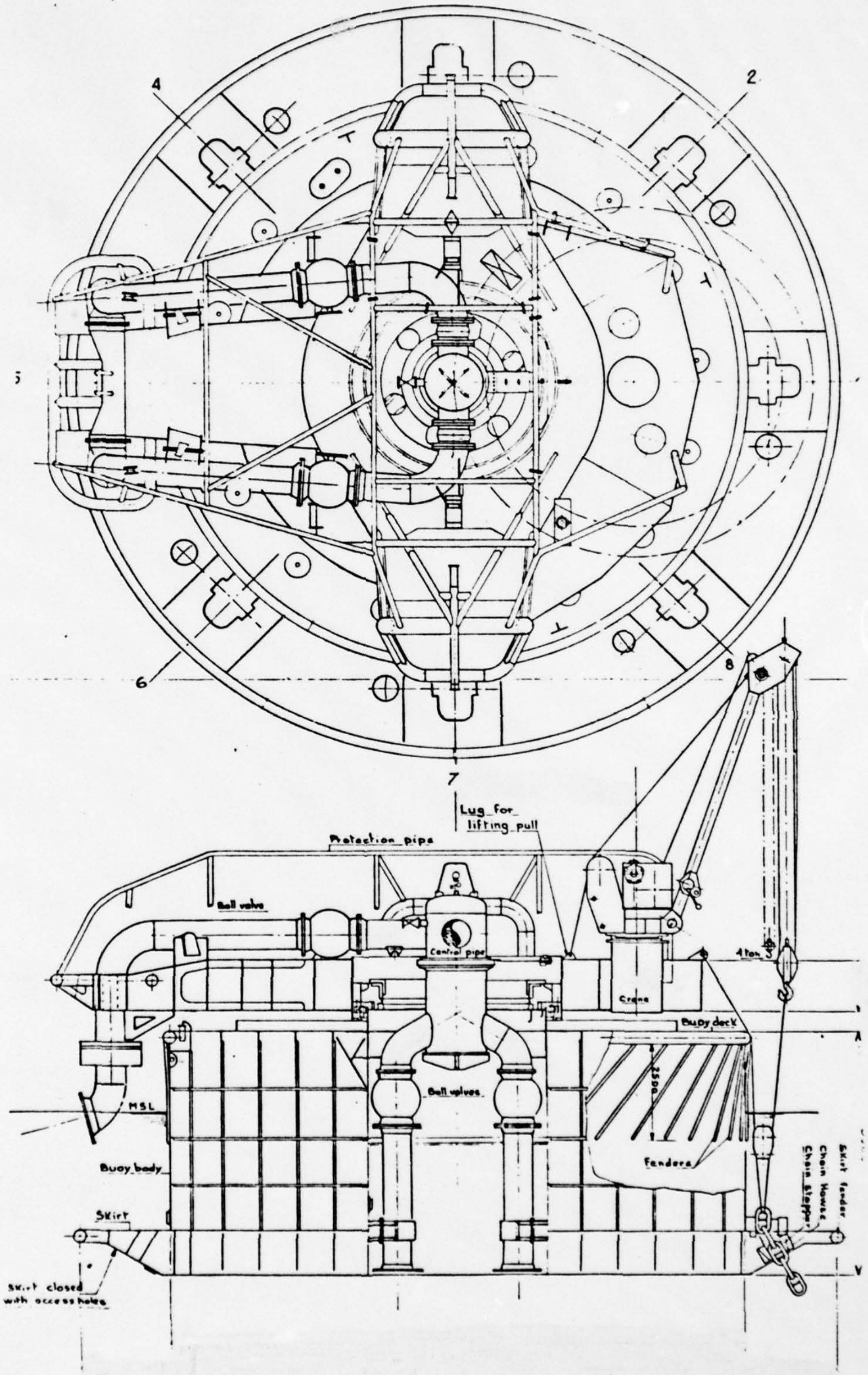

Figure 2-4B. General Arrangement of a Surface Buoy for Catenary Anchor Leg Mooring

Source: Single Buoy Moorings of America, Inc.

The catenary chains permit a flexible response of the buoy to the sea conditions. This, in turn, requires a careful design of the submarine hose configuration. Submarine hose configurations for the CALM are either the Chinese Lantern, the Lazy-S, or the Steep-S. In general, the criteria for selecting the proper configuration depend on the water depth or the wave action. Figure 2-5 shows the arrangement of the three CALM submarine hose configurations, and the displacement of each configuration as the buoy responds to the wave action.

The Chinese Lantern is the generally preferred submarine hose configuration for locations with the following:

- Water depths less than 125 feet;
- Varying current direction;
- Mild wave heights and low wave steepness.

The Lazy-S submarine hose configuration is the generally preferred submarine hose configuration for locations with the following:

- Water depths greater than 125 feet;
- Relatively constant current direction;
- No excessive heaving motions of the buoy.

The Steep-S is the generally preferred submarine base configuration for locations with water depths exceeding 150 feet.

The swivel connecting the buoy to the cargo hose from the ship is on the buoy (Figures 2-4). In addition to possible wear on the seals from the sand and grit in the cargo, the external portion of the swivel is subject to possibly severe corrosion because of its location at the air-sea interface. Manufacturers maintain that this is not a critical factor since corrosion would be a problem at sub-surface locations too. The swivel on the CALM, however, can be easily maintained, subject to the sea conditions, without disassembling the mooring. Details of a CALM fluid swivel, sometimes called a Product Distribution Unit (PDU), are shown in Figure 2-6. Some PDUs carry as many as four different products simultaneously.

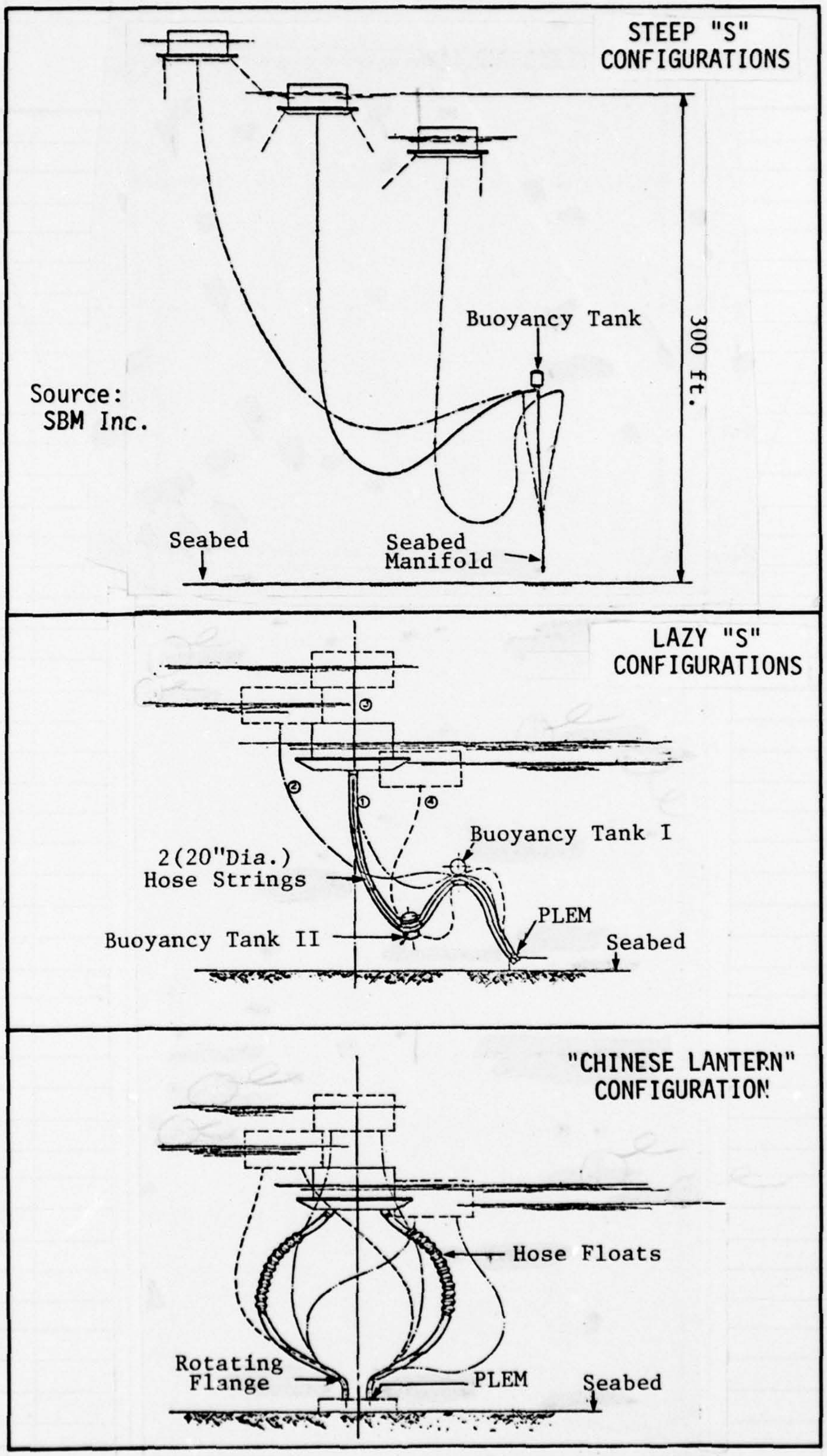

Figure 2-5. CALM Submarine Hose Configurations

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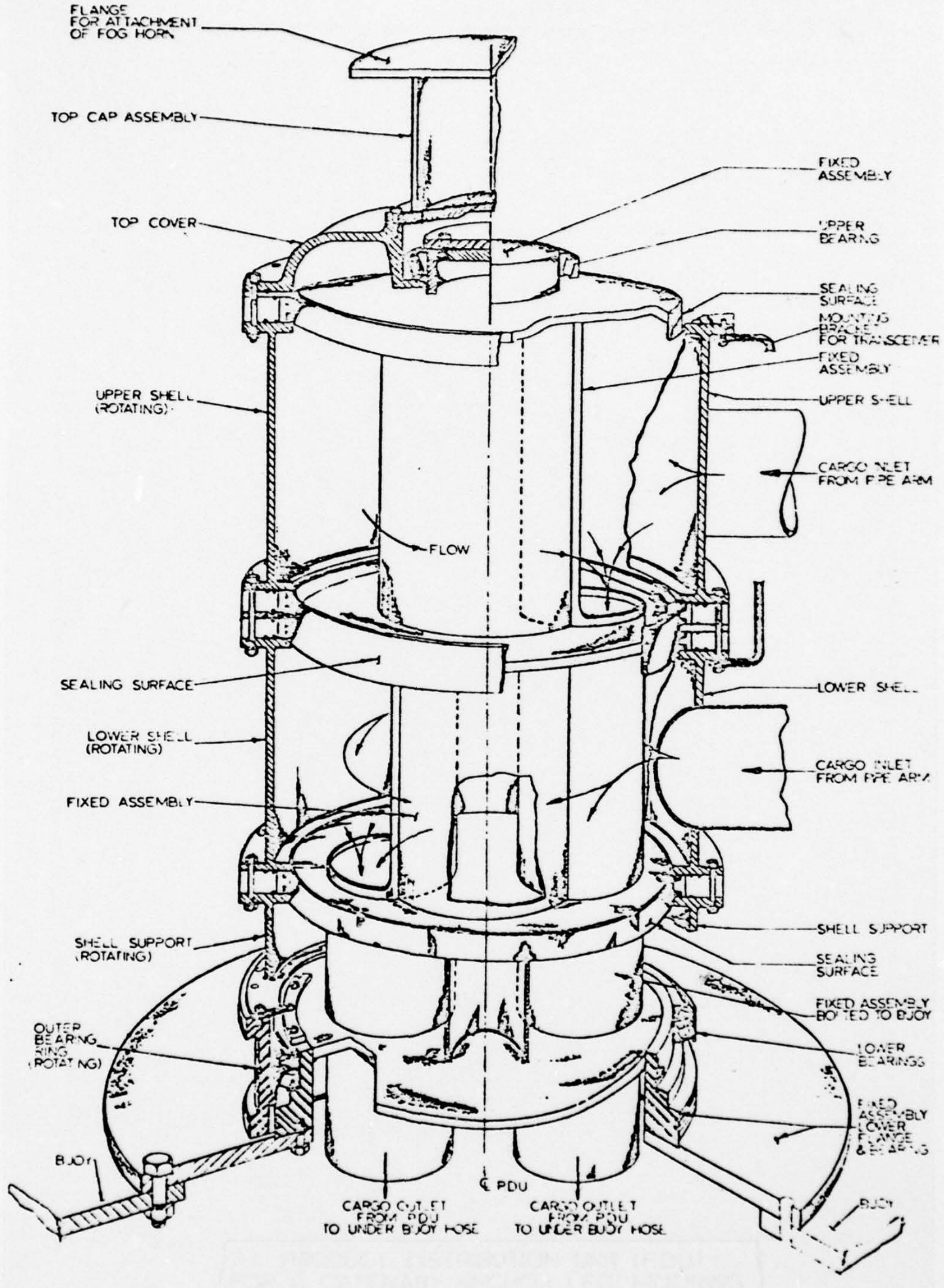

Figure 2-6. A Product Distribution Unit (PDU) for a Catenary Anchor Leg Mooring

Source: IMODCO, Europe, Inc.

As the buoy responds to the sea conditions, the first cargo hose off the buoy to the vessel may be subject to excessive flexing. This wear is due to the fixed connection of the hose to the buoy which must absorb the wave-induced bending movement of the surface hose string and the relative motions of the buoy with respect to the surface hose string. In some installations, swivels have been inserted between the buoy and the floating hoses to reduce the extra flexing of this end of the hose.

The pipeline end manifold (PLEM) is the end of the pipeline connecting the SPM with a shore facility. It is an anchored manifold with isolation valves which can be operated manually or remotely to facilitate maintenance and reduce spill hazards from severe storms. The underbuoy hoses of the CALM system connect the PLEM and the fluid swivel assembly. Lengths of hoses (sometimes piping) connect the fluid swivel assembly of the SALM to the PLEM. A check valve may be positioned in the pipeline after the PLEM to protect against reverse flow to the PLEM. A PLEM for a CALM-type SPM is shown in Figure 2-7.

2.1.2.2 Single Anchor Leg Mooring

The single anchor leg mooring (SALM) is a mooring system consisting of a floating cylindrical buoy anchored to a base assembly on the seabed by a chain riser, or chain and riser pipe combination. In water depths less than 150 feet, the chain alone usually is used. At greater depths, a riser pipe is inserted between the base and the buoy anchor chain. The riser pipe also contains product transfer pipes. The general arrangement of this type of buoy is shown in Figure 2-8.

SALMs have been installed at various worldwide locations in water depths up to 530 feet and located up to 150 miles offshore. Approximately 5 percent of the total number of single point moorings installed by the end of 1976 are the SALM type. However, since the SALM is directly suitable for deepwater mooring applications and since the trend is to install single point moorings further offshore in deeper water and in more exposed locations, the SALMs could occupy a much larger percentage of the total number of single point moorings installed in the

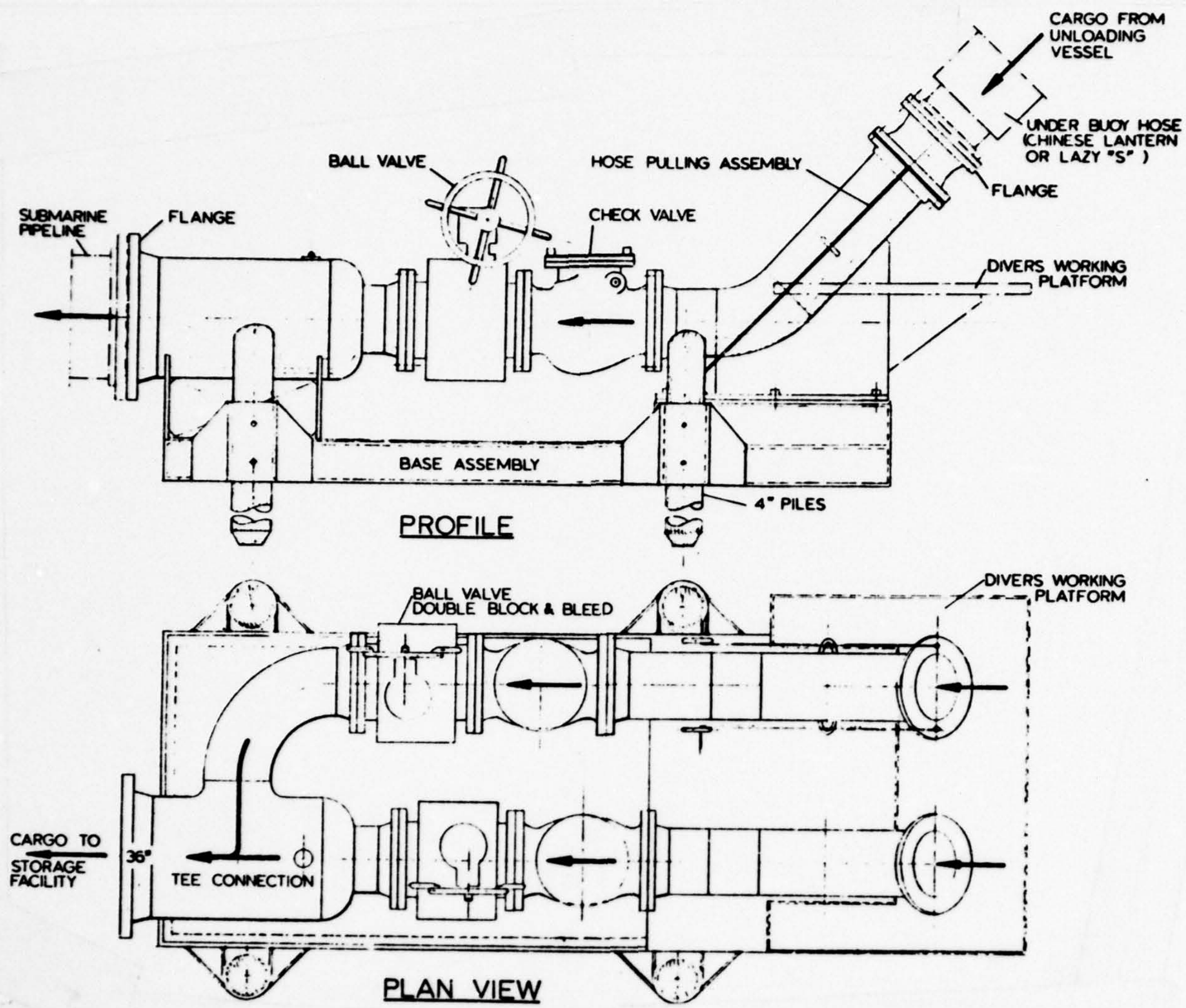

Figure 2-7. Pipeline End Manifold

Source: IMODCO, Europe, Inc.

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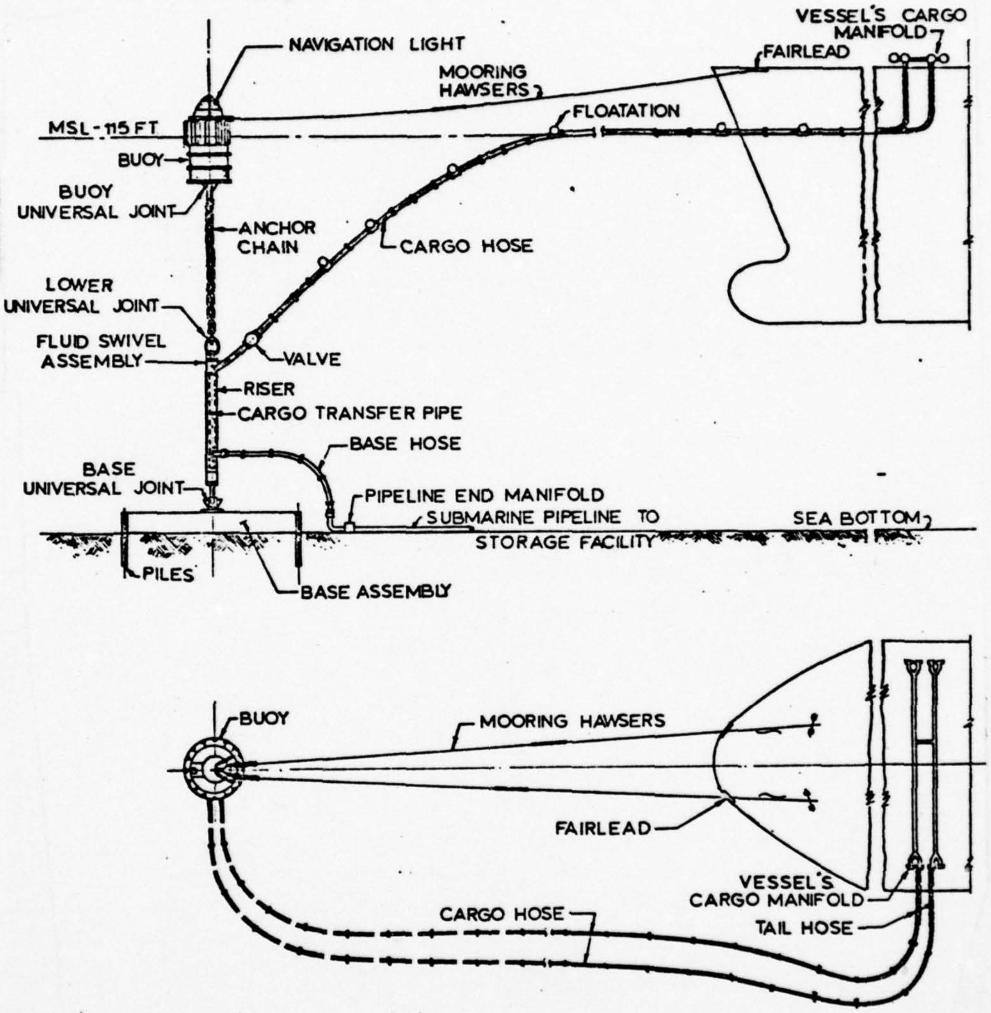

Figure 2-8. Single Anchor Leg Mooring (SALM)

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future. SALMs designed to moor vessels of up to 750,000 dwt (SOFEC) have been installed.

The ability of the SALM to absorb the energy caused by the motions of the moored vessel is a function of the stiffness of the mooring system, which depends on the following:

- Length and elasticity of the mooring hawser.
- Buoyancy of the mooring buoy.
- Distance from the universal joint between the riser and the buoy to the center of buoyancy of the buoy.
- Length and buoyancy of the riser.
- Distance from the universal joint between the base assembly and the riser to the center of buoyancy of the riser.

Because the surface buoy is held by a single anchor leg, it is confined to move in an arc about the base assembly. Since the buoy movement is similar to an inverted pendulum, the restoring moment of the mooring system is due to increased buoyancy as the buoy is pulled to the side. The buoy itself is subdivided for safety and strength for protection if there is contact between the buoy and the vessel during the vessel's approach to the mooring. Also, the mooring buoy is designed to be completely submerged during extreme wave conditions.

The mooring hawsers are connected to anti-chafing chains on the deck of the buoy for protection against excessive wear. The hawsers may be fitted with stress indicators to measure the cyclic tensile stresses when they are connected to the moored vessel.

The mooring base is a toroidial steel shell with steel girders connecting the corners of the shell segments with the center of the base. The shell is ballasted with sand or concrete to resist uplift and sliding. Depending on the soil conditions, the base also may be secured to the seabed with steel piles.

Depending on the water depth, the buoy-to-base anchor system is of two types. For depths exceeding 150 feet, an extra deep buoy is used, which is attached atop of a riser shaft via a universal joint and a swivel in-between. This arrangement is shown in Figure 2-9. The riser shaft is connected to the mooring base via another universal joint. The shaft itself is a large-diameter pipe containing the product transfer pipes. These terminate at the top of the riser pipe in the fluid swivel, which in turn connects to the floating hoses. For shallower depths, the arrangement is similar except that there is no riser pipe; the fluid swivel is mounted directly on the mooring base. This arrangement is shown in Figure 2-10.

The key component to the SALM system is the swivel assembly mounted on top of the riser pipe or mooring base. The fluid swivel assembly allows the leading hose to rotate freely in the vertical direction and to rotate completely around the load carrying shaft. Drawings of fluid swivels for base mounting are shown in Figure 2-11. The buoy mooring force is carried through the swivel housing by a load-carrying shaft connected to the anchor chain. The swivel housing rotates around the load-carrying shaft. The shaft carries the mooring loads to prevent any damage to the seals and bearings which support the fluid swivel housing. As a result, none of the mooring load is carried through the housing bearings.

2.1.2.3 Rigid Single Point Mooring Tower

The rigid single point mooring tower is a stiff mooring system consiting of a cylindrical pylon structure moored to the seabed by a system of piles. A schematic diagram of this system is shown in Figure 2-12.

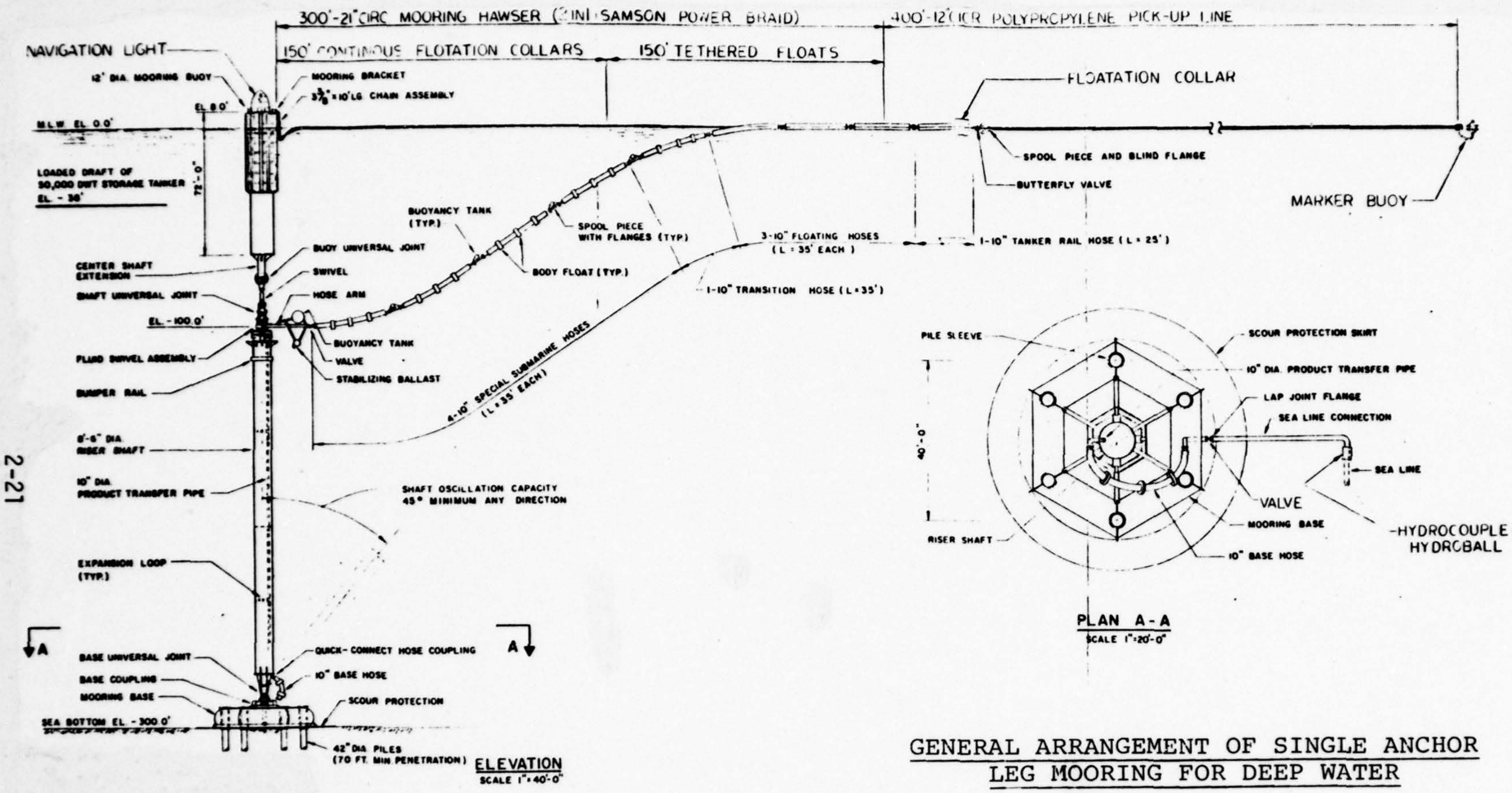
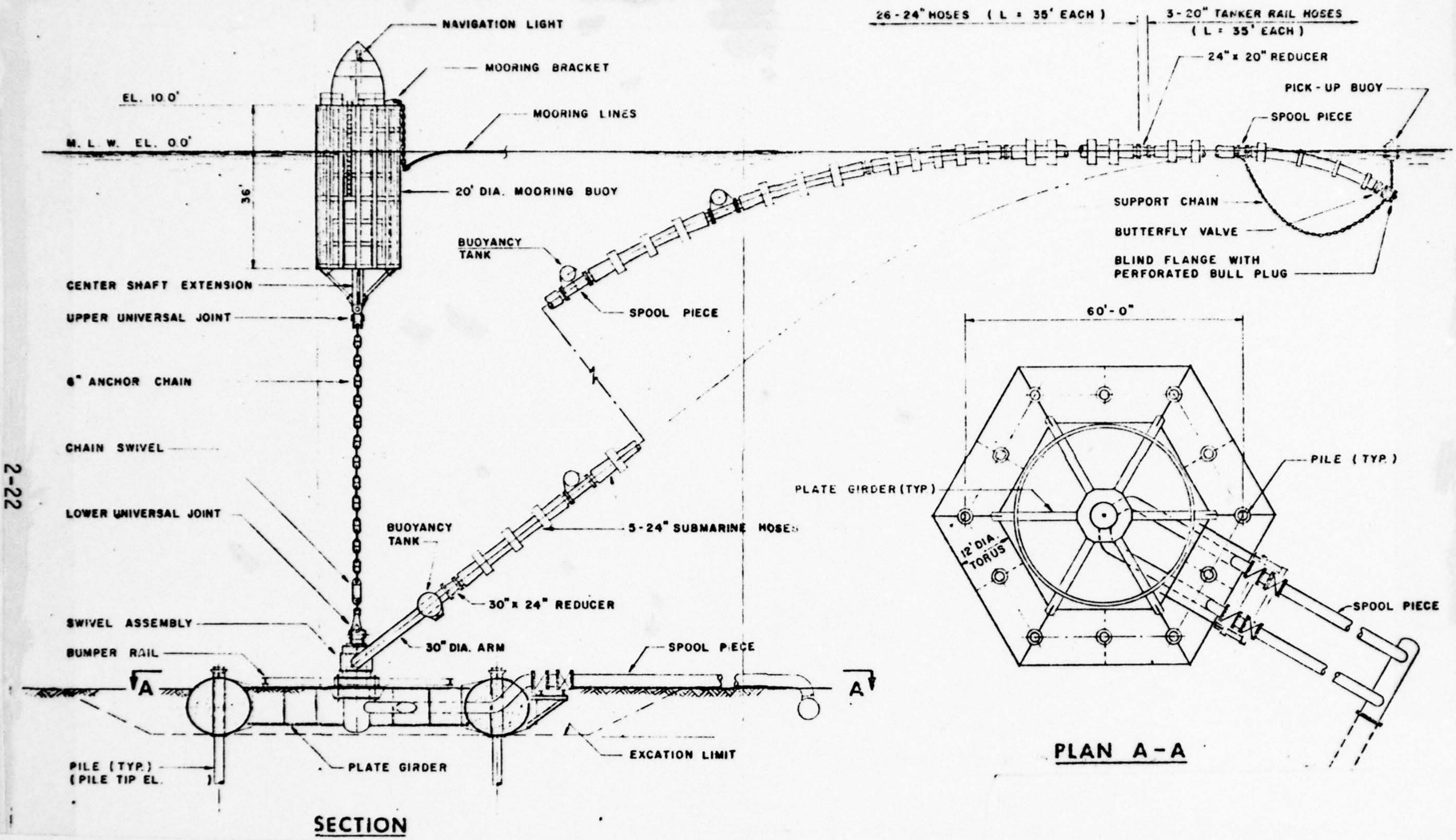


Figure 2.9 General Arrangement of Single Anchor Leg Mooring for Deepwater
(Source: SOFEC, Inc.)



NOTE: TWO PARALLEL HOSE STRINGS EACH OF SIZES AND LENGTHS AS SHOWN IS REQUIRED

Figure 2.10 General Arrangement of Single Anchor Leg Mooring for Shallow Water. (Source: SOFEC, Inc.)

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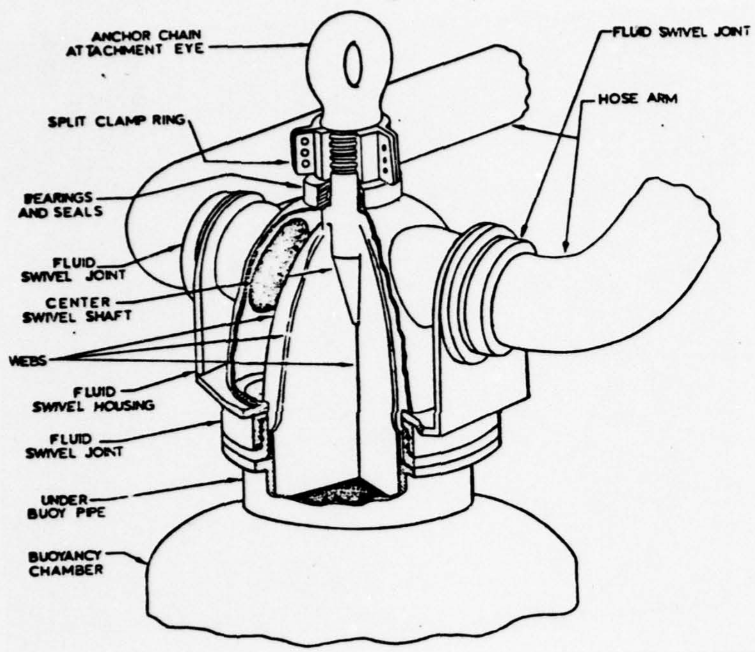
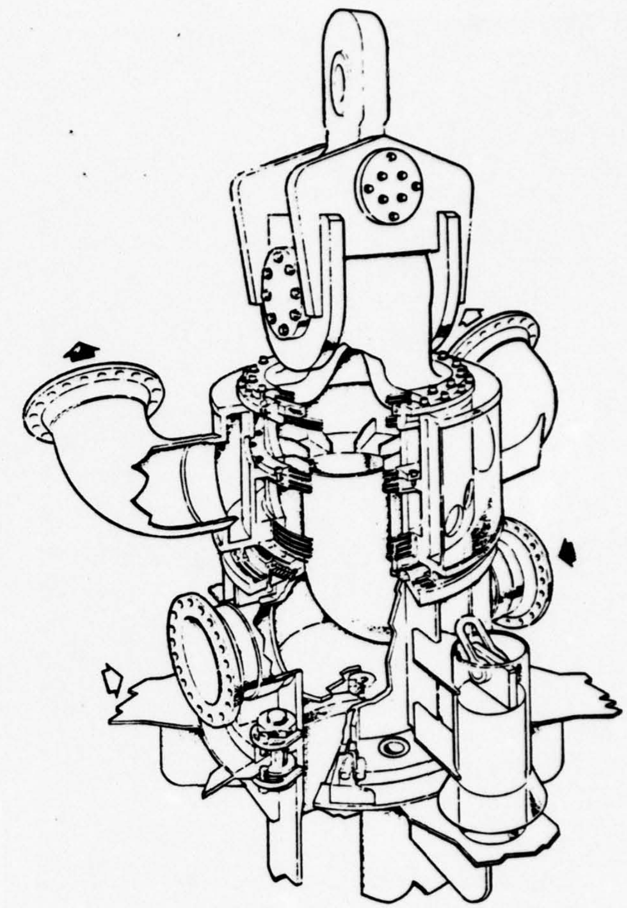


Source: EXXON Research and Engineering Co.



Source: Single Buoy Moorings of America, Inc.

Figure 2-11. Fluid Swivel Assemblies for a Single Anchor Leg Mooring Cut-Away View

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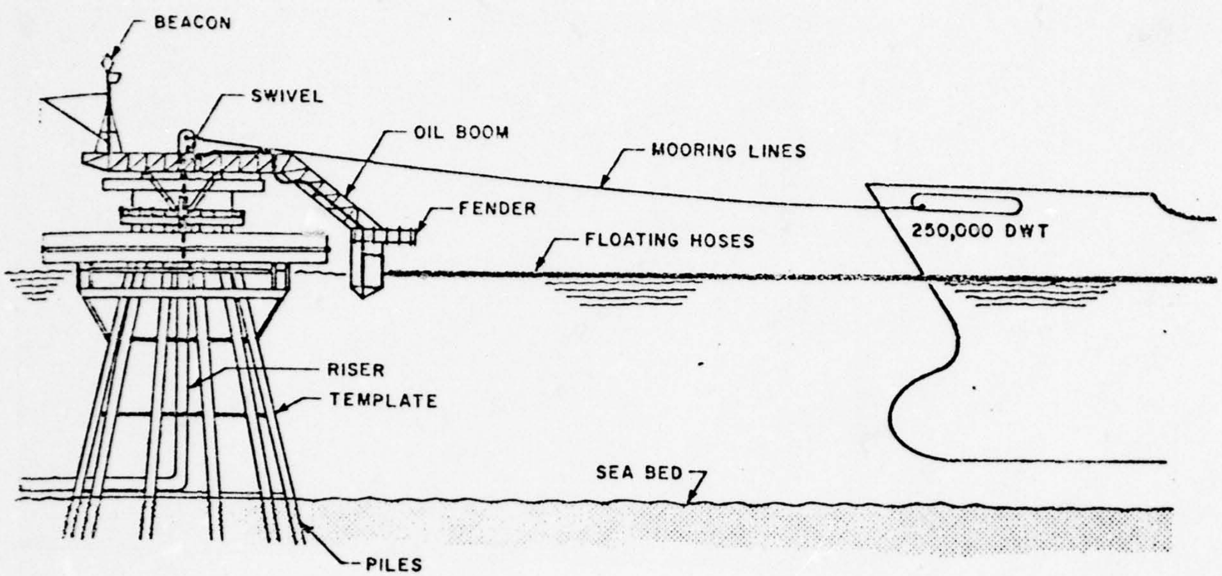

Figure 2-12. Rigid Single Point Mooring Tower

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Fixed single point mooring towers have been installed in the Mediterranean Sea and off Scapa Flow. Approximately 2 percent of the total number of single point moorings installed by the end of 1976 are this type. The water depths at these installations are about 100 feet. All the installations of this type have been designed for vessels up to 100,000 tons deadweight.

The piles that make up the cylindrical structure are also used to support a circumferential fender ring. This fender ring serves to protect the mooring from contact damage with the ship.

The advantage of the single point mooring tower is primarily to eliminate use of submarine hoses, providing a reduced vulnerability of the cargo transfer system. The disadvantage of the single point mooring tower is that as a fixed point mooring, the system is more vulnerable to damage by ramming. The single point mooring tower requires a calmer and shallower water than either the CALM or the SALM.

2.1.2.4 Single Buoy Storage

The single buoy storage (SBS) is a flexible restrained mooring system consisting of a floating cylindrical buoy with a rigid arm or yoke connected to a permanent storage vessel. The buoy is moored to the seabed by a network of anchor chains. Actually, the single buoy storage is a modified catenary anchor leg mooring in which a rigid arm or yoke replaces the mooring hawsers, and a steel structure and hard piping replaces the floating bases. Figure 2-13 is a diagram of an SBS.

SBSs have been installed in locations in the Mediterranean Sea, Arabian Gulf, and Indonesia. SBSs have operated successfully in water depths to 240 ft and located 15 to 80 miles offshore. Approximately 2 percent of the total number of single point moorings are the SBS type.

The buoy itself is a central tank for piping and is subdivided into compartments for safety and strength. The buoy must have adequate buoyancy to support the anchor chains, the submarine hoses, the center swivel, the center turntable and part of the rigid arm. The rigid arm and the turntable are one unit.

All outgoing oil pipes from the buoy are secured at the top of the rigid arm and connect to the storage vessel via swivels or short hoses. The arm is connected to the stoarge vessel by hinges.

The catenary anchor chains supply the mooring support for the buoy and moored vessel. The criteria for the number, the layout, and the seabed securing of the anchor chains is similar for the SBS as for the CALM.

The criteria for selection of the submarine hose configuration are similar to those for the CALM. The storage vessel is a dedicated vessel permanently moored to the rigid arms. An existing ship may be modified with hinges to accept the rigid arm and used as the storage vessel. The unloading vessel then moors alongside and the cargo is transferred.

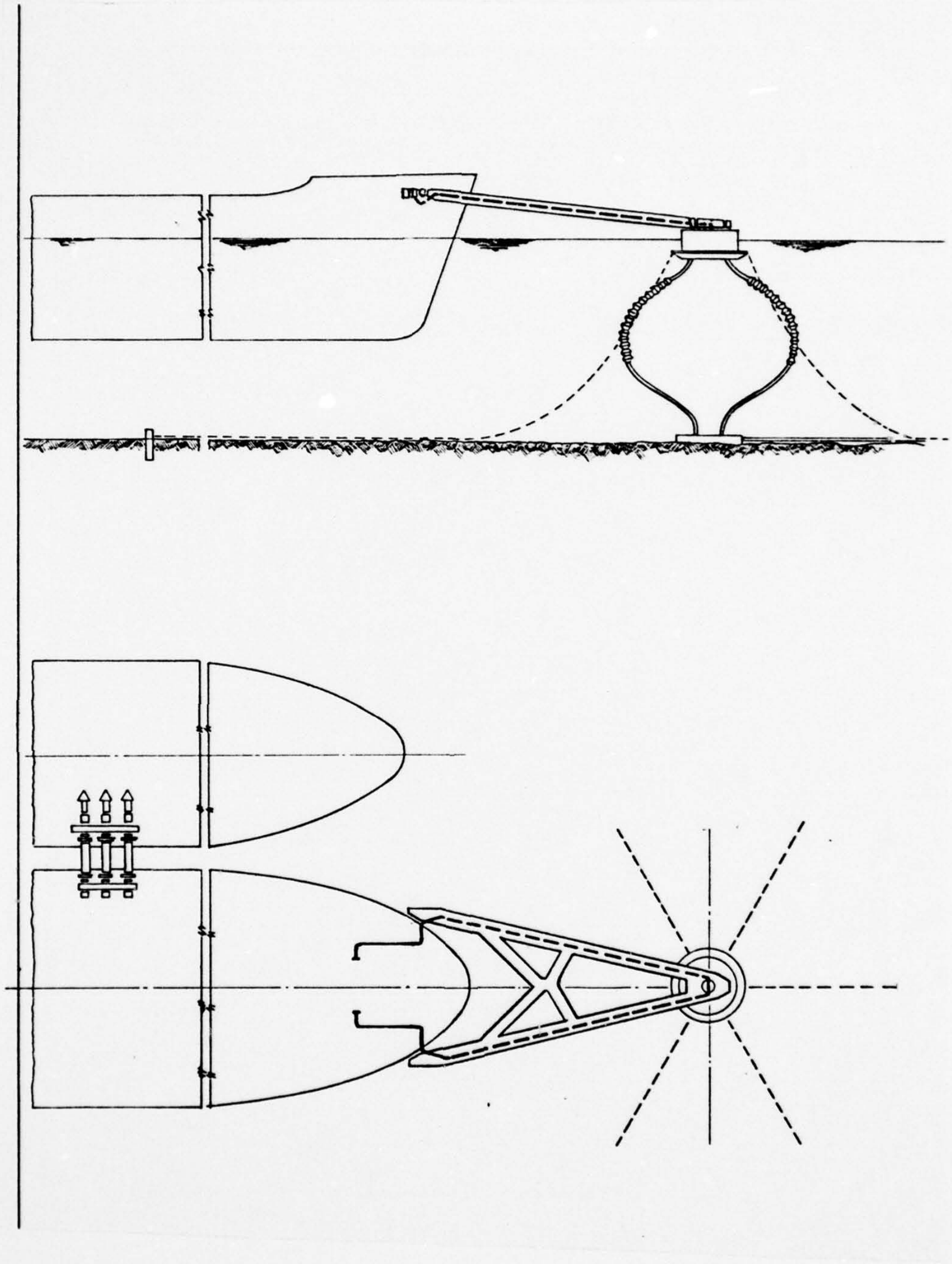

Figure 2-13. Single Buoy Storage

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Although not contemplated for use as a U.S. deepwater port, the principal advantage of the SBS is that the cargo is transferred from vessel-to-vessel. This reduces the floating cargo hose problem and allows higher pumping rates for faster vessel turnaround. The principal disadvantage of the SBS is the high initial cost of the storage vessel.

2.2 CHARACTERISTICS OF EXISTING DEEPWATER PORTS

The first single point mooring was installed in 1959. In the period of 1959 through 1976, there have been a total of about 203 single point mooring installations. Although companies in the United States are licensed to build single point moorings, all the single point moorings have been installed in waters outside the territorial limits of the United States. Figure 2-14 shows the breakdown by geographic area of the total number of single point moorings installed through 1976.

Figure 2-15 shows the worldwide trend of the single point mooring installations. The growth of the number of single point moorings reflects their popularity with the oil industry. The reasons for this are relatively low initial cost, fairly easy installation, high reliability, and versatility with water depth.

The first operative single point mooring, the catenary anchor leg mooring (CALM) type, was installed in Sweden in 1959. There have been several single point mooring systems designed during the 1960s, but the CALM was almost the only type of a single point mooring installed from 1959 to 1969. The only exceptions were two fixed mooring towers, especially designed for shallow-water application. The first mooring tower was installed in 1962, and the second was installed in 1964.

From the period of 1959 to 1969, all the CALMs were installed in shallow water and in areas which either were relatively secluded from heavy sea conditions or had a mild sea state. In 1969, the first

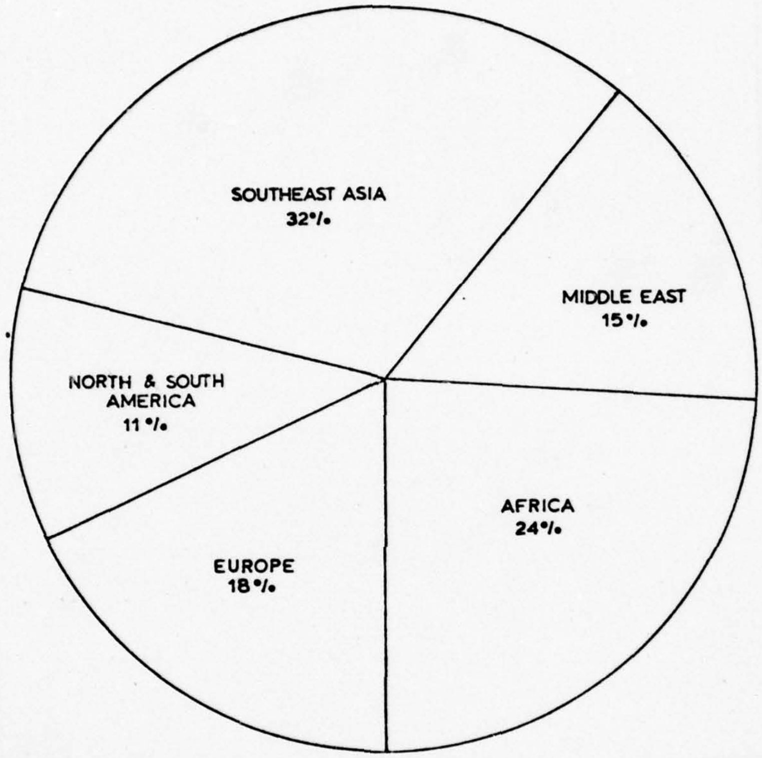

Figure 2-14. Geographic Distribution of Point Moorings Installed

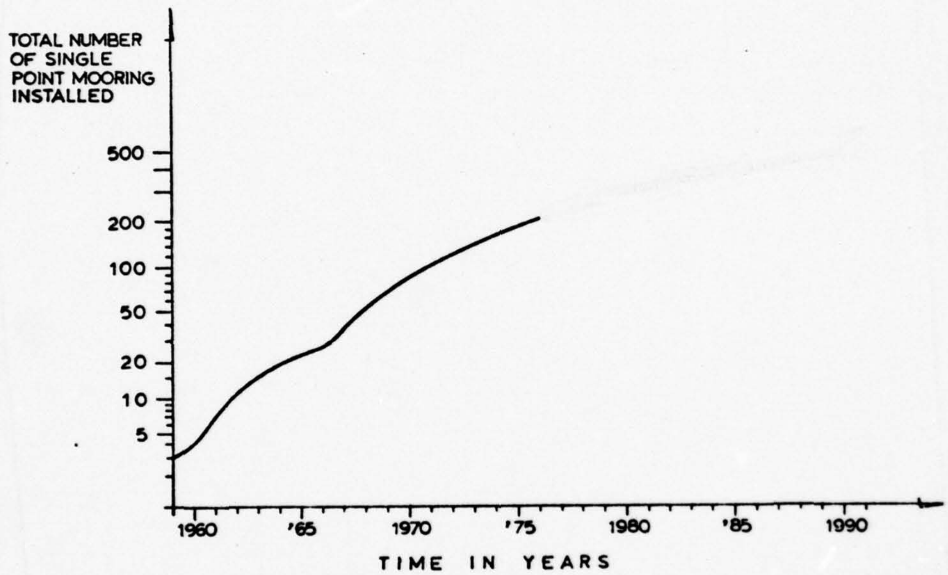

Figure 2-15. Growth Rate in the Number of Single Point Moorings

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deepwater CALM was installed. This installation was near Durban, South Africa, and the water depth was 150 feet. This buoy was close enough to shore to be serviced with mooring launches.

Also in 1969, a second advance was made in the deepwater application of single point moorings. The first single anchor leg mooring (SALM) was installed in Libya at a water depth of 140 feet.

The Libya and the South Africa installations proved that single point moorings could be laid and operated successfully in deep water. This provided an incentive to install single point moorings in water which is even deeper. A further incentive was the development of new mooring techniques, which enable the vessel to connect to the mooring hawser and to the cargo hose without the aid of a launch.

The demand for more single point moorings in exposed environments has prompted the development of new designs. These designs include the Exposed Location Single Buoy Mooring (ELSBM)*, the Single Buoy Storage System (SBS)*, the SPAR, the articulated tower mooring system, and other designs which have not been built. Figure 2-16 shows the distribution of the single point moorings in service through the end of 1976.

By the end of 1977, single point moorings have been used successfully in exposed sea conditions, in water depths exceeding 500 feet, and at locations 150 miles from the shore.

Characteristics of single point moorings, located worldwide, are tabulated in Appendix A. Included are the location, type of mooring, and selected prevailing environmental conditions.

U.S. installations, being new, will have the advantage of much accrued experience, especially in design, maintenance, and inspection. Many industry representatives feel that many of the problems that have plagued existing DWPs either will not exist or will be much less severe for U.S. installations. Most of the existing single point moorings are located either in remote areas of the world or at distances from five to ten miles offshore. With the exceptions of ARAMCO's terminal facility installed at Ju'aymah, Saudi Arabia, and the single point moorings installed in offshore oil production fields, the pumping

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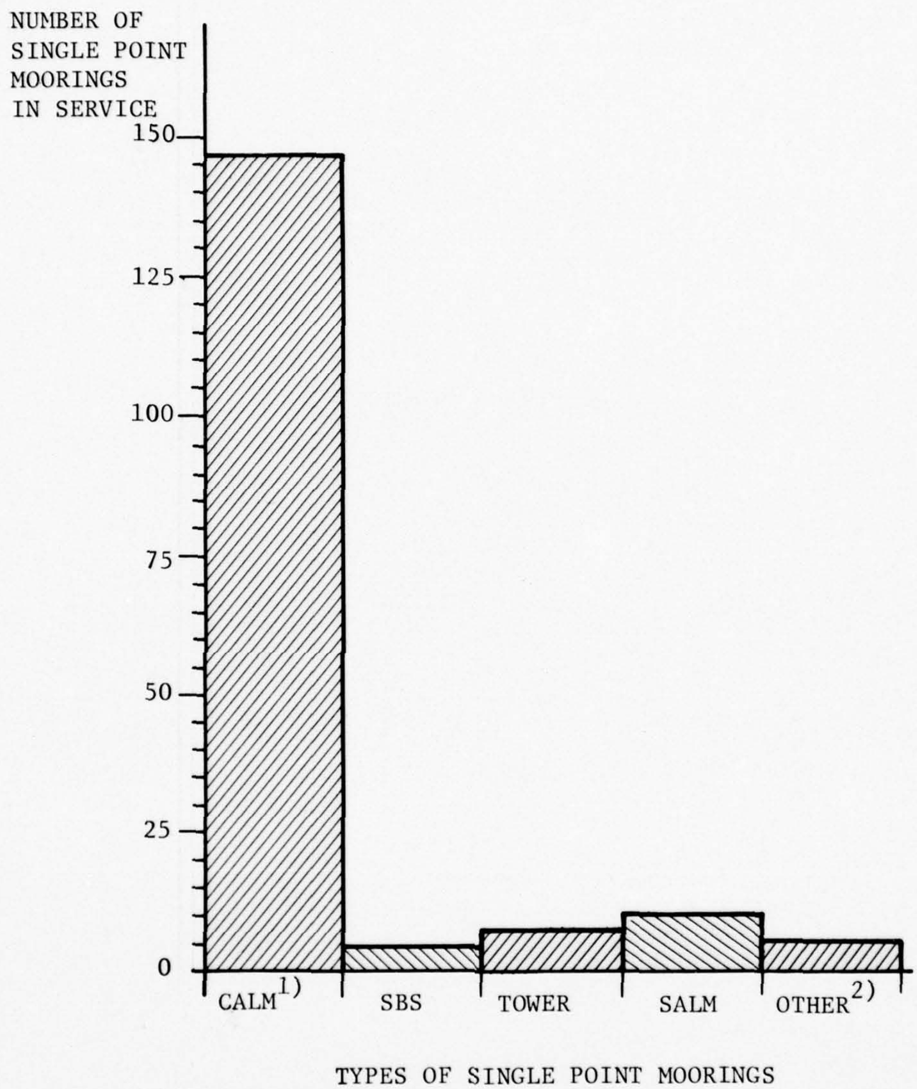
*A product of Single Buoy Moorings, Inc.



1) Number of CALMs in service does not include 17 older CALMs taken out of service.

2) Other includes: ELSBM, taut anchor leg, SPAR.

Figure 2-16. Distribution in Number of Single Point Moorings

and metering operation for single point mooring terminals, used as loading facilities, are controlled from the shore. Some industry representatives feel that this lengthens the response time for shutdown in an emergency at a loading facility compared with an unloading facility. This fact, together with the higher pumping rates at a loading facility versus an unloading facility, may contribute to larger volumes spilled at loading facilities compared with unloading facilities. As will be discussed in Section 3.2, the cause for an emergency shutdown often may be the overflow or impending overflow of a tankship's cargo tank.

The operators of foreign single point mooring terminals, who are familiar with the availability of spare parts in the U.S., feel that a single point mooring terminal in the U.S. would not be as difficult to operate satisfactorily as would a similar facility in a foreign country. Comparing the availability of spare parts for the offshore drilling industry in a foreign area and in the U.S., drilling operators measure the waiting time for spare parts in terms of hours or days for drilling operations in the U.S. and in terms of months for drilling operations in foreign offshore areas. Single point mooring terminal operators feel the same analogy would be true for U.S. offshore terminals.

The marine environmental conditions for U.S. deepwater port locations generally are not as severe as are the environmental conditions at most foreign locations. The environmental conditions for many U.S. locations are comparable to the conditions in the Mediterranean Sea or the Persian Gulf.

The actual wave conditions for future single point mooring installations in the U.S. must be determined based on the specifically proposed locations. However, Table 2-2 summarizes the wave conditions for the Gulf of Mexico, particularly off the coasts of Lousianna or Texas. Waves in excess of six feet are of particular interest for the

design and operation of a single point mooring in the Gulf of Mexico. Design practices for offshore structures for the Gulf of Mexico are well established. Part of this practice is to design for hurricane conditions rather than the cyclic fatigue loadings experienced on marine structures elsewhere in the world.

Table 2-2

REPRESENTATIVE WAVE HEIGHTS FOR THE GULF OF MEXICO NEAR THE LOUISIANA COAST
Source: LOOP Inc.

Wave Height	Percent of Time
0-2 feet	60%
2-4 feet	25%
4-6 feet	10%
> 6 feet	5%

Most of the problems and about 80 percent of the spillage volume at foreign single point mooring terminals is related to surface cargo hoses. In the CALM design, the first hose off the buoy must absorb the wave-induced bending moment of the entire hose string, and a confused sea can cause severe torsion in the hose sections. The results are the cause of hose problems at foreign single point mooring installations. The wave conditions in the Gulf of Mexico may be confused at times, but in general, the waves are not very high nor very steep. The mild daily sea states in this area are expected to contribute to reduced problems for SPM compared to many foreign locations.

2.3 DESIGN AND CONSTRUCTION STANDARDS

The concept of the single point mooring design was developed by the major oil companies. Approximately 95 percent of the single point mooring installations at the end of 1976 are owned and operated by oil companies or their affiliates.

2.3.1 Oil Companies International Marine Forum

Technical and operating personnel of the various oil companies participate in the Oil Companies International Marine Forum (OCIMF). OCIMF meets regularly to discuss various technical problems particular to various aspects of the oil industry. OCIMF formed a special committee, the Buoy Mooring Forum, in 1966. Until 1975, the committee met semi-annually, alternating between New York and London, to discuss the operating problems and recommendations for improving the design, construction, inspection, maintenance, and testing various components of single point moorings. Although the meetings consisted of open discussions of the problems of single point moorings, most of the problems were particular to specific installations. However, the most common problem with many installations was the cargo transfer hose.

A result of the Buoy Mooring Forum meetings has been the publishing of guidelines for single point moorings, especially standards for cargo hoses.

The Single Point Mooring Forum Hose Standard is for rubber, wire-reinforced oil suction and discharge hoses for offshore moorings. The purpose of the Standard is to provide the minimum acceptable technical requirements to ensure the satisfactory performance.

The standards give both the technical requirements for commercial hoses and the technical requirements for prototype hose approval.

The former include the following:

1. Performance requirements
2. Length
3. Flexibility
4. Construction
5. Required tests
6. Marking
7. Packing

8. Classification of hoses

   a) Submarine hose
   b) Submarine hose with special reinforced ends
   c) Floating hose with integrally built-in flotation medium
   d) Floating hose with individual flotation units
   e) Tanker rail hose

The technical requirements for prototype hose approval includes the following:

1. Drawings
2. Size of prototype hose
3. Required tests for prototype hoses

The Buoy Mooring Forum Hose Guide is for the handling, storage, inspection, and testing of hoses in the field under service conditions. The guide lists requirements for the following:

1. Handling
2. Storage
3. Inspection and testing

The Buoy Mooring Forum SPM Hose Ancillary Equipment Guide provides a common description of the terminology and technical requirements for the designer and operator of SPM systems.

The Buoy Mooring Forum SPM Hose System Commentary is a description of the terminology of single point moorings, and an outline of present practice in the design of hose systems. The types of single point moorings described are as follows:

1. Catenary Anchor Leg Mooring
2. Single Anchor Leg Mooring
3. Single Point Mooring Tower
4. Vertical Anchor Leg Mooring

The hoses that are described are as follows:

1. Submarine Hoses for the Catenary Anchor Leg Mooring
2. Submarine Hoses for the Single Anchor Leg Mooring
3. Floating Hoses

4. Hose to Buoy Connection

5. Float/Sink Hose

Standards OCIMF has recommended for tanker manifolds and associated equipment are aimed at introducing conformity in manifold arrangements for all ocean-going tankers engaged in the transport of bulk liquid petroleum. Their objective is to assure more efficient arrangements for connection to buoy moorings and alongside berths.

2.3.2 Marine Classification Societies

The marine classification societies are a major influence on the shipping community, because their design and construction standards assure the soundness of the marine structure. The standards are established by technical personnel, and the standards are constantly being compared to existing designs and their performance history. These rules do not discuss the cargo transfer operation.

The American Bureau of Shipping has issued rules dated 1975, entitled Rules for Building and Classing Single Point Moorings. These rules give the standards for the design of the structural components of the single point mooring and the requirements for classification of the single point mooring. Det Norske Veritas and Lloyd's Register of Shipping are preparing their own rules for the construction of single point moorings. Like the American Bureau of Shipping, these rules will give the standards for the design of the structural components of the single point mooring and the requirements for classification of the single point mooring.

2.4 OIL TRANSFER SYSTEM

The type of deepwater ports (DWP) heretofore proposed for U.S. waters is an offloading facility with undersea pipelines, pumping plaform, and an array of single point mooring buoys (SPMs) with floating hose connections for the oil tankers. This type of facility is selected for consideration in this safety analysis. The oil transfer system analyzed extends from the ship's onboard manifold to the storage tanks (but not including the tanks) of the onshore facility. This includes all the

elements unique to a deepwater port facility, used for either loading or offloading purposes.

2.4.1 System Description

The principal constituent parts of the oil transfer system (OTS) are illustrated in Figure 2-17. The design of this facility is a composite of the designs for SEADOCK and LOOP as presented in References 1 and 2 and are in accordance with the latest USCG regulations.

The tankships and VLCCs (Very Large Crude Carriers) which can be accommodated by the DWP range in size up to 550,000 DWT. The limiting parameter is the water depth at the SPMs which must permit 5 feet net underkeel clearance (after allowance for vessel movement), Coast Guard DWP regulations, 33 CFR 150.337. (For both LOOP and SEADOCK, the water depth is about 100 feet at the SPMs).

There will be six SPMs associated with the DWP. Each SPM will be equipped with two hose strings for offloading, a monobuoy, and a connection (the PLEM) with the undersea pipline to the platform. Each hose string is 1300 feet in length and is comprised of 30-40 foot sections of flexible floating hoses with flanged ends bolted together. The hose strings are equipped with navigational aids along their length and a blind flange and butterfly valve at the free end. The monobuoy provides the mooring for the VLCC and contains a swivel which allows free rotation of the hoses about the buoy.

Generally, a VLCC is moored to the buoy via two hawsers, each of which is 200 feet long and capable of sustaining the mooring strain. However, many SPM operators have changed to the use of a single hawser because the yawing motion of a moored ship tends to place the entire mooring load on one or the other hawser anyway. The buoy itself can have several designs, but the two most common are the Catenary Anchor Leg Mooring (CALM) and the Single Anchor Leg Mooring (SALM). These have been described in Section 2.1.2.1 and 2.1.2.2.

The SPM pipelines (Figure 2-17) are buried, 48-inch OD pipelines, each about 8,000 feet long. One line connects each SPM to the pumping platform. The pipe will be of a grade and thickness to withstand

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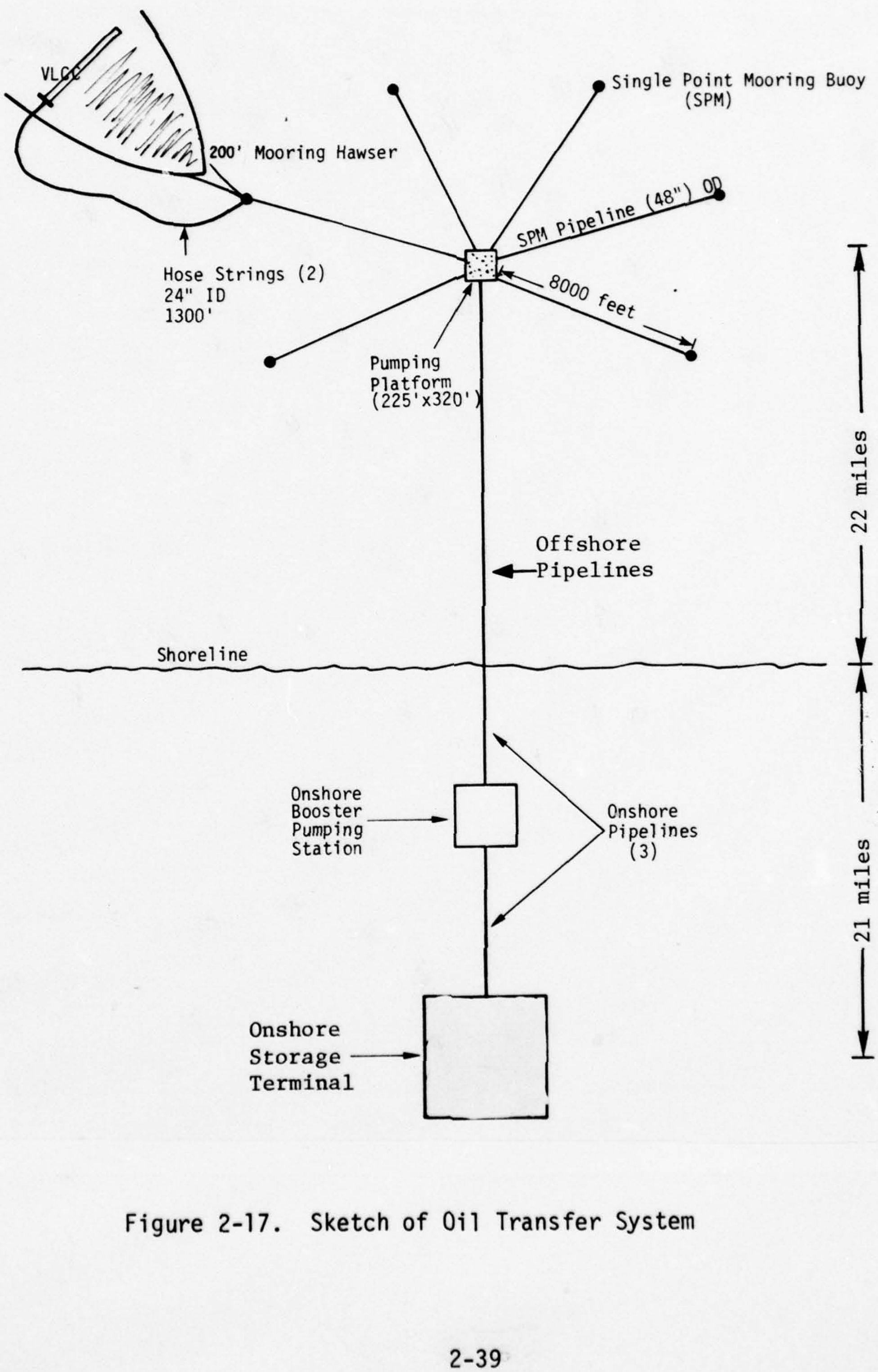

Figure 2-17. Sketch of Oil Transfer System

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the operating conditions and the generally greater laying stresses during installation. The pipe will be coated with a coal-tar mixture to resist corrosion and will be covered with concrete for negative buoyancy. Finally, the SPM pipelines will be buried so that the top of the pipe is five feet below the sea floor.

The pumping platform, located about 22 miles offshore, serves as a booster station for the ship's pumps. The dimensions of the pumping platform of this composite DWP design are 225' x 320'. Presumably, a quarters platform for offshore personnel would be located adjacent to the pumping platform, but since the potential for oil spill from the crew's quarters is nil, no detail is supplied for it. The SEADOCK design calls for two pumping platforms, with the second being planned to meet the maximum throughput of 4×10^6 bbl/d. The SEADOCK platforms are 26 miles offshore and the LOOP pumping platform is 18 miles offshore. The platforms are constructed according to standard industry practices for offshore structures and U.S. Coast Guard Regulations.

A schematic of the equipment arrangement on the pumping platform is shown in Figure 2-18. For simplicity, the equipment which is involved directly with the transfer of oil is shown on one deck of the platform and all equipment which is a part of the waste treatment system is on another deck. The six SPM pipelines are manifolded to allow the greatest flexibility in routing oil to specific trunklines or away from equipment which is out of service. The valves on the platform, other than control valves, are welded gate valves. All of the equipment shown has drain lines and valves which are used during maintenance or repair. These are not shown in Figure 2-18.

The sampler is an in-line sampling device which automatically collects a portion of the oil in the line for analysis (for a more complete description of the individual components, see Section 2.4.3). Strainers and air eliminators are placed upstream from the pumps for protection of the pump mechanism.

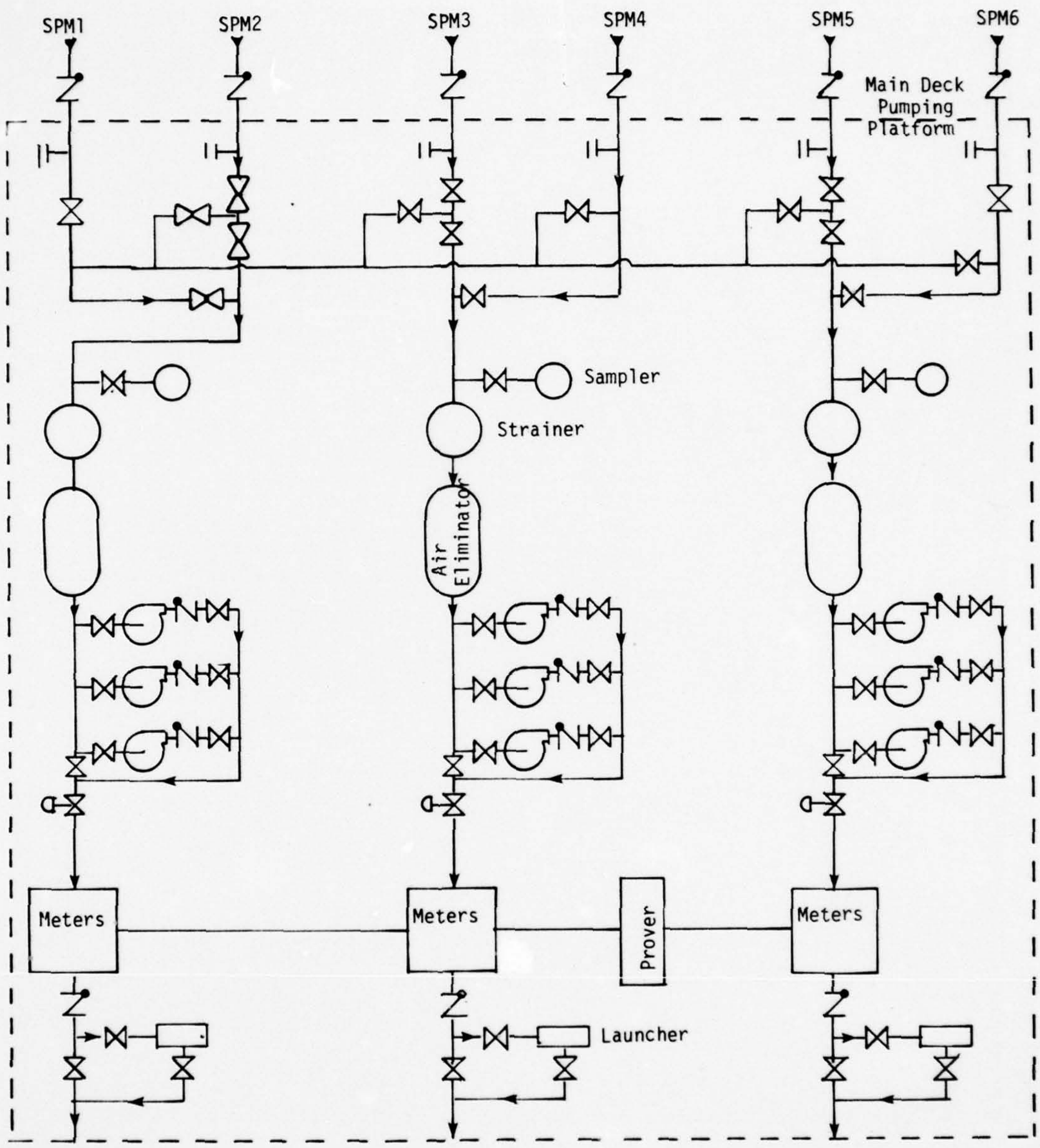

Figure 2-18. Pumping Platform Schematic

Source: LOOP, Inc.

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The maximum pumping rate for the platform is 300,000 bbl/hr. The LOOP design utilizes electric motor driven pumps with three 6000 hp pumps in parallel for each of three lines. SEADOCK plans for a total of nine liquid fueled, aircraft-type turbine driven pumps, each with 15,000 hp. SEADOCK allows one of the pumps to be used on either of two oil pumping lines as necessary. For simplicity, the LOOP pump arrangement was selected. The pumping rate is established by a control valve to match the offloading rate of the ship.

Each oil line passes through a meter and proving run on the pumping platform. The meter runs are illustrated in Figure 2-19. There are five separate metering lines on each oil line. Each metering line is comprised of two isolation valves, a flow straightener, a turbine flow meter, and a control valve. The meter lines are connected to the meter prover which is the calibration instrument. The prover line returns this oil to one of the three main oil lines. Each oil line is equipped with a launcher for passing scrapers and other pigs through the pipelines to the onshore storage facility.

The waste disposal system on the pumping platform is illustrated in Figure 2-20. It includes the oily water waste disposal system and the recovery of oil from the maintenance drain lines. All oil that can be reclaimed is returned to the pipeline and all water is cleaned before it is returned to the sea. Gases recovered from the lines and tanks are vented to the atmosphere. The runoff from rains or spills onto the deck are collected by the deck drains and flow into the oily water sump. The fluid then is pumped into the skimmer tank, and the oil that is skimmed off is pumped into the reclaimed oil tank. The remaining fluid is pumped into the oil and water separator tank. The water recovered here goes to the sea sump. There is an emergency overflow from the skimmer tank to the sea sump. The drains from all oil transfer equipment on the pumping platform go to maintenance oil drain tank. This oil can be pumped to the reclaimed oil tank or pumped back into the equipment being serviced. All tanks in the waste disposal system are open to the vent drum and vented to the atmosphere. The waste disposal system is a closed

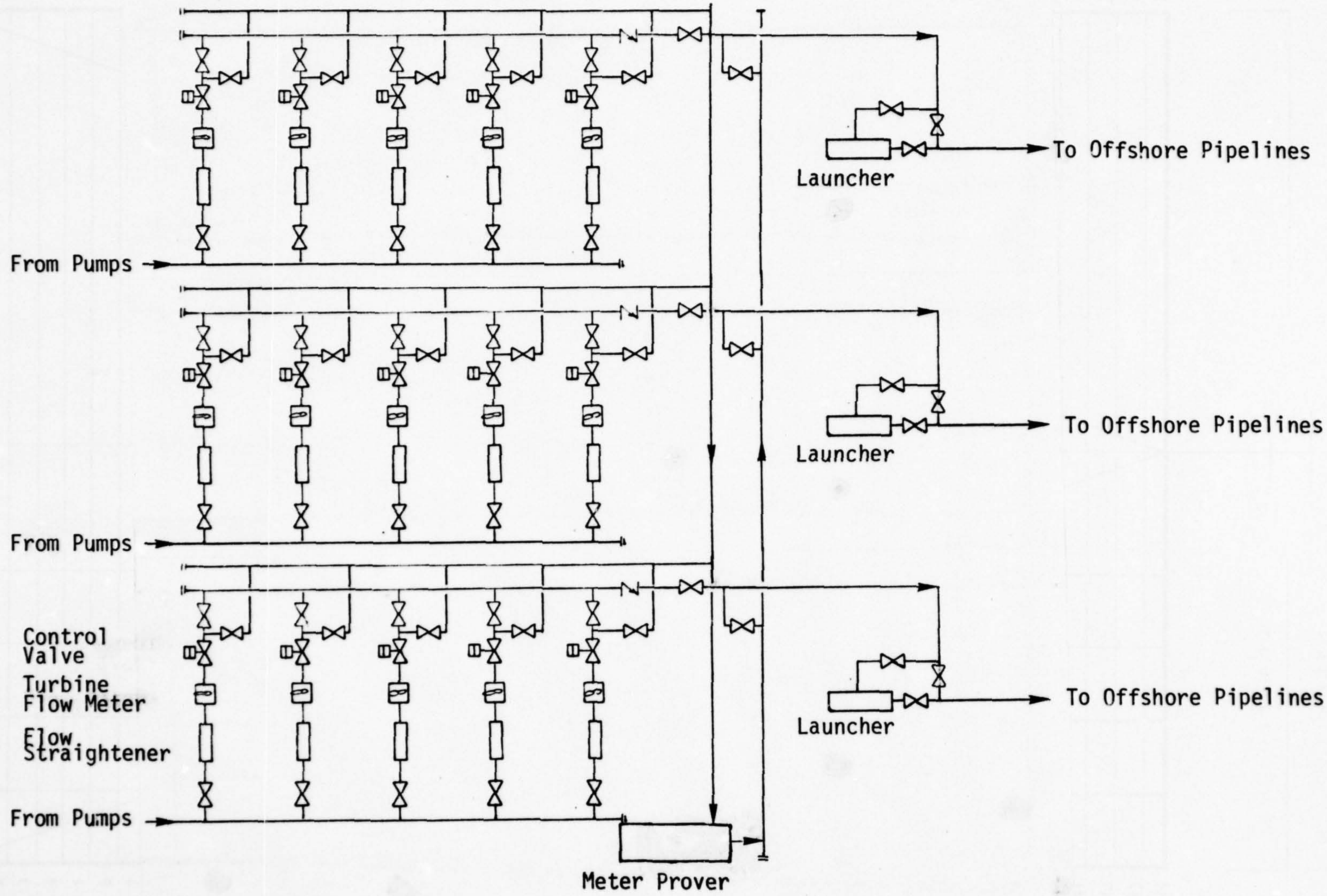

Figure 2-19. Meter Runs

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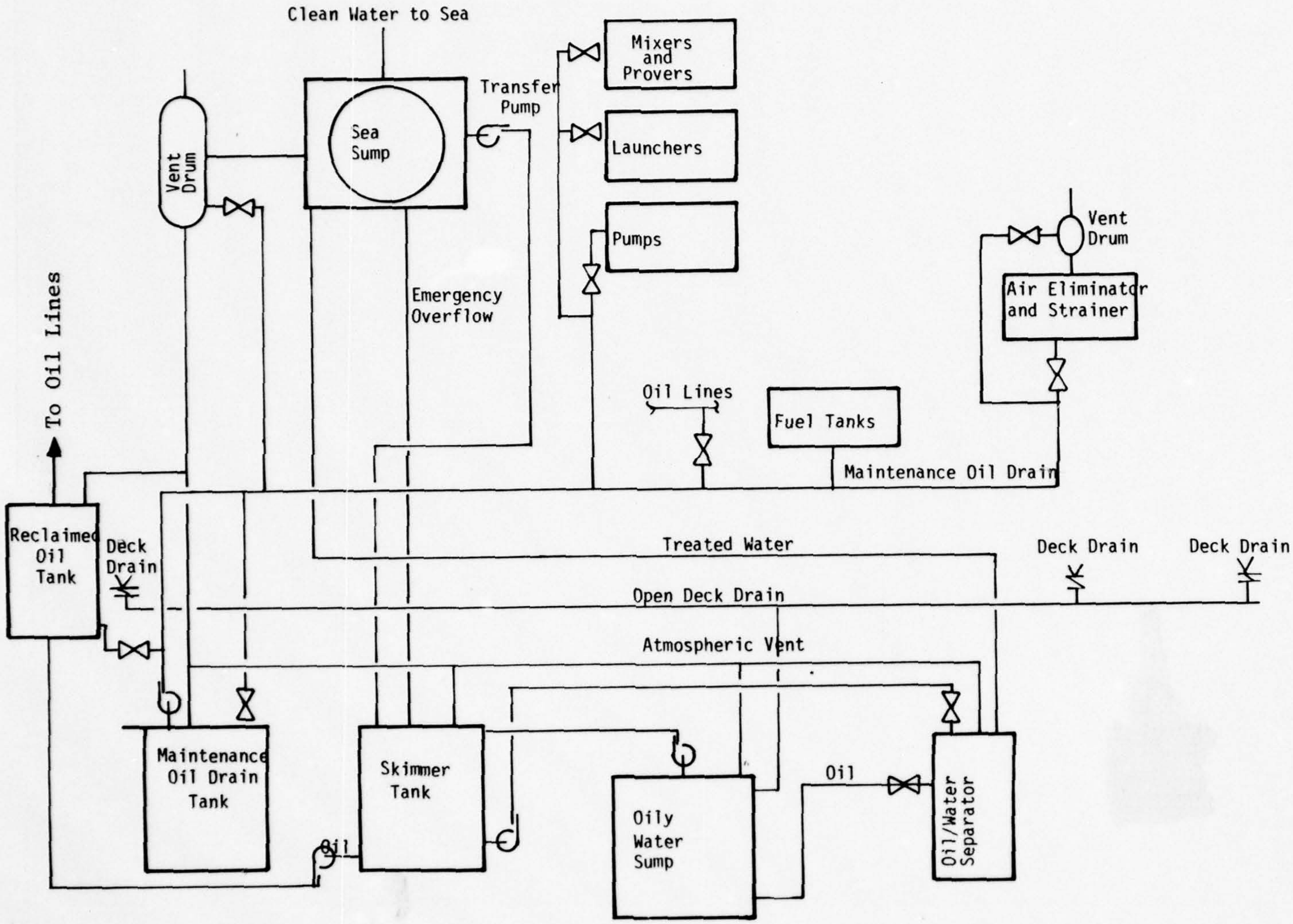

Figure 2-20. Waste Disposal System

Source: Seadock, Inc.

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system with only those openings mentioned above.

There are three pipelines between the pumping platform and the onshore storage facility. Each is 48 inches outside diameter and 43 miles long. The offshore portion of the pipelines is constructed in the same manner as the SPM pipeline and has the same corrosion and concrete coatings. It is 22 miles long and is buried to a depth of 3 feet, except under shipping lanes and safety zone where the depth will be 4 feet. The onshore section of the pipelines will be buried to a depth of 3 to 4 feet in accordance with 49 CFR 195.248. The onshore pipeline will be about 21 miles in length.

The onshore terminal facilties for this DWP include a booster pumping station one mile inland and a storage tank farm 21 miles from the shoreline. This arrangement resembles LOOP in the length of the onshore pipeline and SEADOCK in the use of conventional steel tanks for storage. A schematic of the booster pump station is shown in Figure 2-21. The number and arrangement of pumps is similar to the pumping platform. A by-pass line facilitates scraping and pigging the pipelines.

Figure 2-22 illustrates the elements of the onshore storage facility which are included in this study. These comprise the scraper receivers, meter runs, meter prover, receiving manifold, pressure relief system, and oily water separator. The entire facility will be served by a drainage system for collection of spilled oil and oily water run-off from storms. Equipment such as the meter runs and scraper receiver traps would be mounted in areas with concrete curbing which would have separate drains to an oily water separator. Each storage tank is set inside a berm dike of sufficient size to contain the contents of the entire tank in the event of a catastrophic failure. Additionally, the tank farm itself is assumed to have a perimeter dike of sufficient capacity to contain the run-off from a 100-year storm. It is assumed that the tank farm contains 20 tanks of $1x10^6$ bbls capacity each.

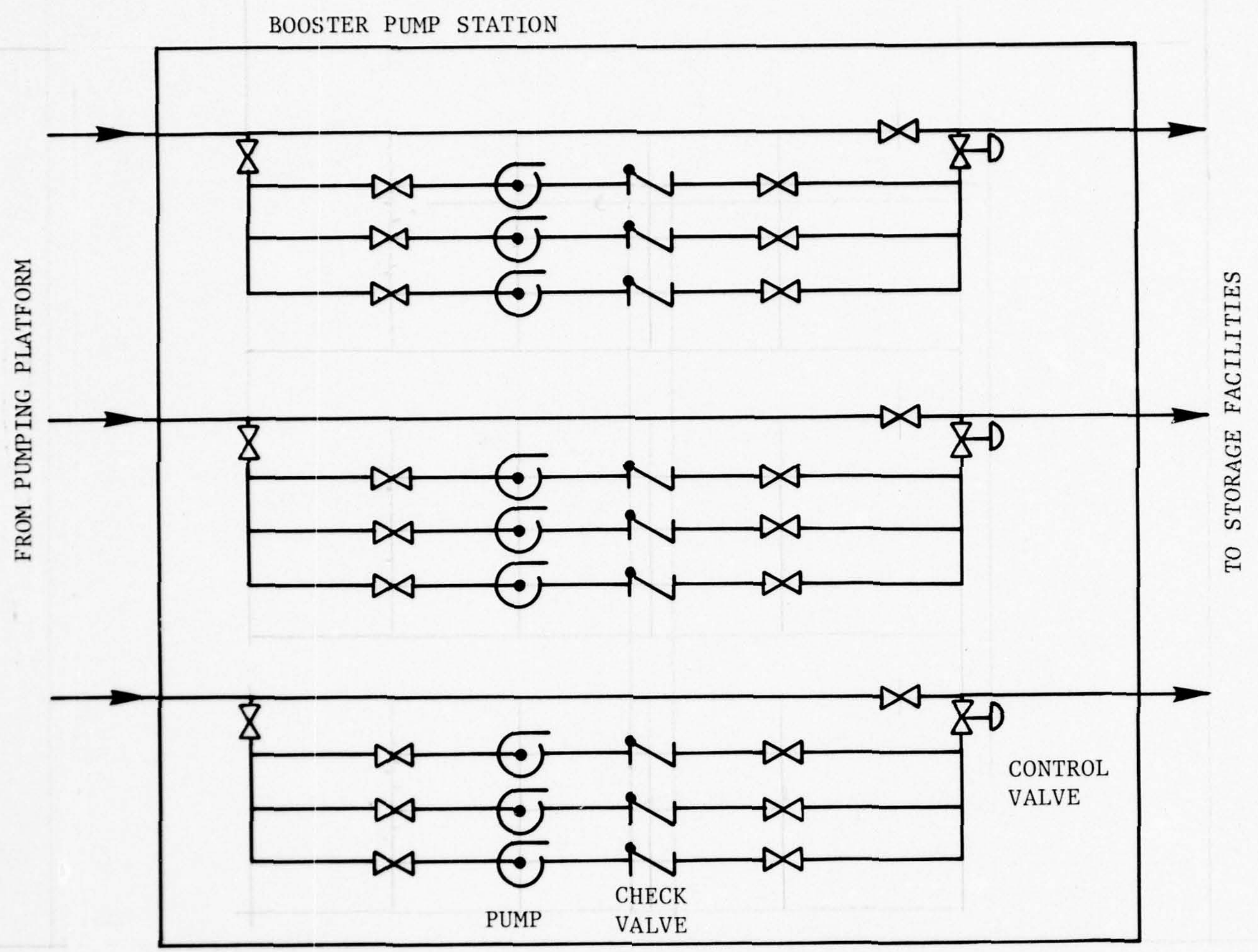

Figure 2-21. Schematic of the Onshore Booster Pumping Station

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Considerable flexibility is required to make efficient use of the storage facilities, hence the tanks are connected by a network of pipelines not shown in Figure 2-22. The assumption is made that there is a total of 10 miles of buried and above ground pipeline for distributing the incoming oil to each tank (2600 feet each for 20 tanks). Also, the number of individual valves present in the receiving manifold and pipelines have not been specified, but it was assumed that there were approximately 60 of all types.

The pressure relief system discharges to the oily water separator in which oil is reclaimed. Water from the separator passes into settling ponds before discharge from the facility. Reclaimed oil is pumped to one of the tanks for storage.

2.4.2 Description of Operations

The throughput rate for the composite DWP used in this study is 3.4×10^6 bbl/d. Additionally, it has been assumed that the average VLCC carries 1.6×10^6 bbl of crude oil (250,000 DWT class of ship) and has an offloading rate of 100,000 bbl/hr. This implies that the average ship requires at least 16 hours to transfer its cargo. An average of 776 ships per year would berth at the DWP. With 6 SPMs available, this throughput rate means that oil transfers would be underway an average of 24 percent of the total time available at each SPM.

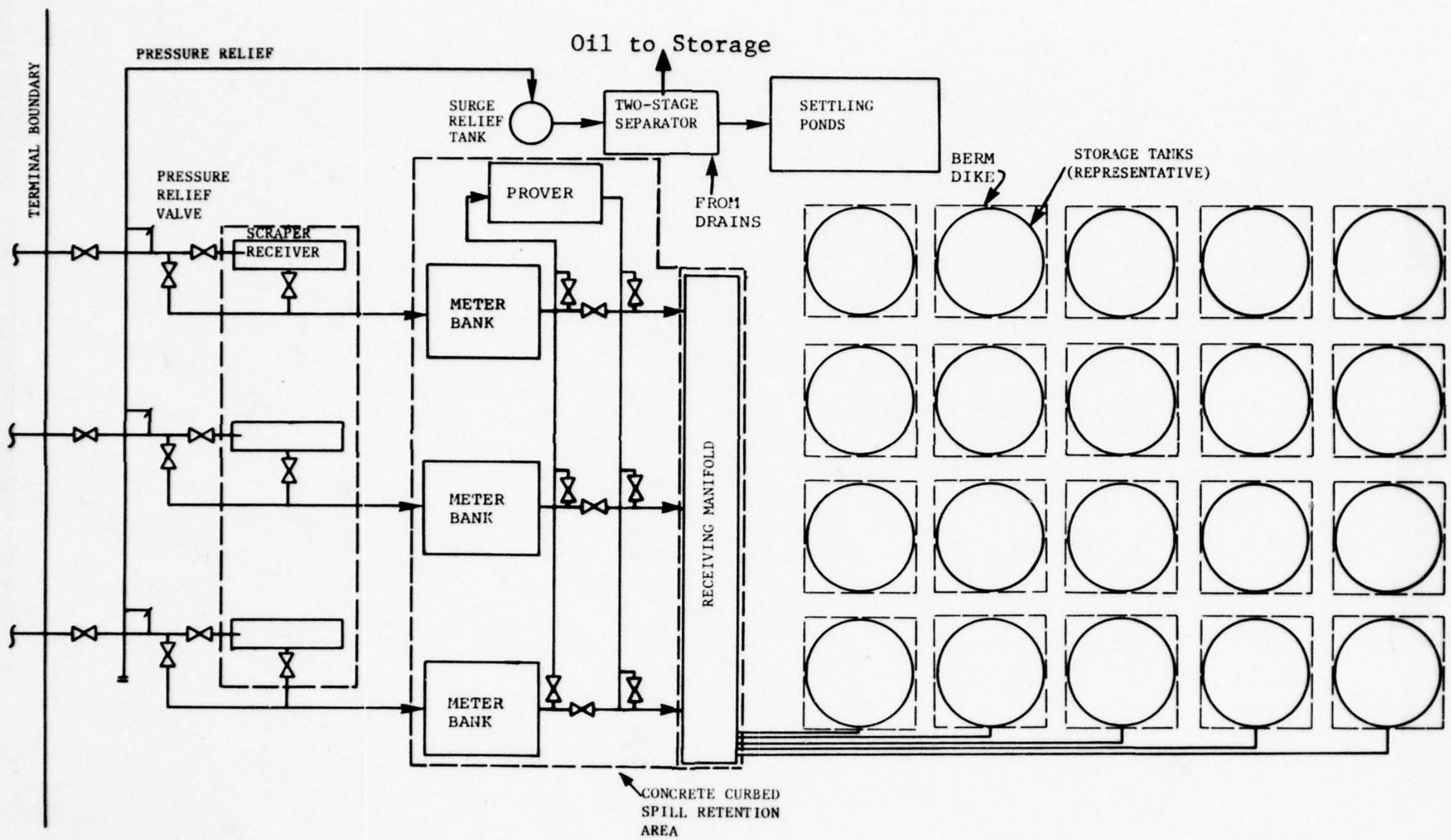

Figure 2-22. Schematic of Onshore Storage Facility

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The operation of the DWP is controlled by the personnel who hold six positions. Their titles and responsibilities are described below:

1. Port Superintendent

- overall responsibility for the port operation
- movement of vessels to and from the berths
- transfer of oil through the port facilities
- prevention, containment and clean-up of spills
- decision to cease oil transfer or disconnect moored ships due to adverse weather
- evacuation and/or shutdown of port due to adverse weather

2. Cargo Transfer Supervisor

- direct responsibility for the oil transfer operations
- supervises the accuracy of quality checks, metering operation
- responsible for spill mitigation and prevention measures

3. Vessel Traffic Supervisor

- supervises all vessel movement
- dispatches service vessels
- maintains radio communications
- records all vessel activities while in port
- collects and distributes weather reports
- maintains radar surveillance of the safety zone, traffic separation scheme and anchorage area.

4. Cargo Transfer Assistant

- boards the ship prior to transfer
- certifies cargo quantities aboard the ship
- maintains communication with the Cargo Transfer Supervisor during the transfer
- observes the transfer operation

5. Mooring Master

- boards the ship 5 miles outside safety zone
- advises the captain of the ship
- directs the ship to the berth
- supervises the berthing of the ship
- obtains signed checklist for the port's safety requirements

6. Assistant Mooring Master

- boards the ship prior to mooring at the SPM
- assists the approach and berthing operation from the ship's forecastle
- directs the connection of the mooring lines

The safety rules of the port to which each ship must adhere are listed on a checklist to be completed and signed before transfer can begin. The ship must keep the engines in a ready condition, must have firefighting equipment, power and lighting available, must have officers and seamen on duty during the transfer, and must have plugged the scuppers. Smoking and the use of transistor radios and other electrical appliances on deck would be prohibited or restricted.

Each VLCC which departs another port bound for the DWP must notify the Vessel Traffic Supervisor of its estimated time of arrival and cargo information. This communication is repeated three days, 24 hours, and 12 hours prior to the ship's arrival. The port requests information about the ship's manifold, requirements for bunkering, stores, and medical attention, and the boarding provisions for the Mooring Master and crew.

Personnel from the DWP board the arriving ship 5 miles outside the safety zone. The Mooring Master maintains the latest weather advisory and informs the captain of the best route and speeds for the berthing operation. Two motor launches assist the berthing, one to keep the hoses clear of the ship and one to deliver the mooring hawsers to ship.*

Once the mooring hawsers are secured and the pretransfer checklist has been completed, the hose hookup begins. The hoses and SPM are inspected for visible leaks. Then the hoist is connected to the lifting

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*Generally only one launch is required. At existing single point moorings the ship approaches the mooring at a 45^{o} angle to the cargo hose. A grapnel gun is used to launch a grapnel up to 300 feet to pick up the hawser. Either the launch is used to bring the hose to the ship, or a grapnel is launched and connected to a tail on the cargo hose. The launch may then be used to connect the ship's cargo gear to the spreader on the cargo hose.

buoy and the hose is lifted to a predetermined height where the holding chains are connected to the hose string. Anti-chafe blankets are placed under the hose at the ship's rail. The blind flanges are removed and the hose is bolted to the ships' manifold. The connection is then inspected and verified.

The Cargo Transfer Supervisor signals the ship to open the valves and pressurize the system. The hoses are checked visually from the launch again for leaks. The pumping rate is increased to the maximum if no leaks are found and continues until the cargo is transferred. Metering of the cargo is performed on the pumping platform for leak detection purposes and custody transfer.

The disconnect procedure under normal conditions is the reverse of the connect procedure. Transfer operations must be discontinued if wave heights exceed 12 feet or the windspeed exceeds 40 mph. VLCCs must be disconnected from the mooring if wave height exceeds 15 feet or if the sustained windspeed exceeds 50 mph. Service vessels and launches are not permitted to operate when wave heights exceed 6-8 feet.

Large leaks from the oil transfer system (between the pumping platform and shore facility) are detected by frequent flow rate and volume comparisons between the pumping platform and onshore facilities. Surveillance of the ship to pumping platform distance is the principal leak detection method for that region. Monthly checks of the offshore pipelines by airplane also are planned.

2.4.3 Components

In this Section, the principal components of the oil transfer system will be described from a functional viewpoint. The control system for the DWP has been excluded since only preliminary designs exist thusfar and is the subject of a separate study by the U.S.C.G.

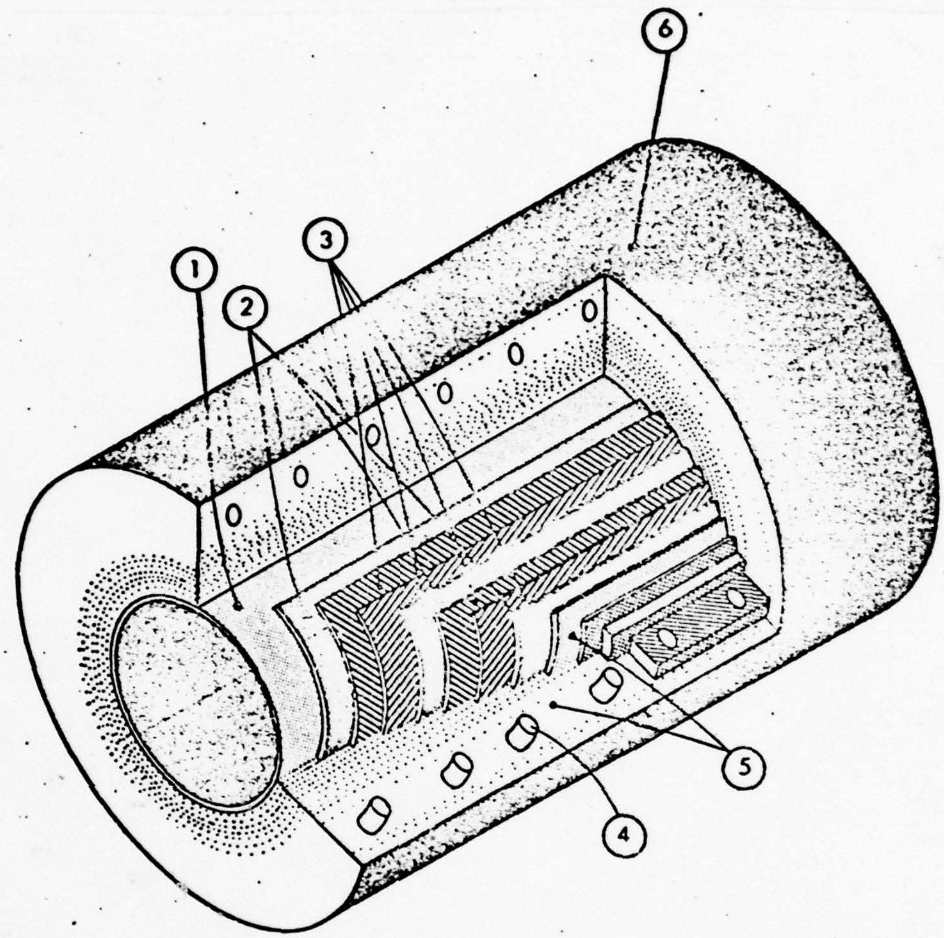
1. Flexible Hose Strings. The flexible hose strings are each about 1300' long and composed of sections about 30-40' long. The portion

of hose that is to be lifted to the ship's manifold, called the tail hose, is subjected to more stress and strain; consequently, it is usually of smaller dimensions and these sections must be replaced frequently. The tail hose sections constitute about 140' of the total hose length. The ship-end of the tail hose has a blind flange and butterfly value. The remaining hose sections are 24" ID hoses which are connected with bolted flanges at each end. The hoses in use in DWP in other parts of the world use hoses with 16"-24" ID. A schematic of the construction details of a hose is given in Figure 2-23. In some cases, the hose has flotation material as an additional outside cover, and in others flotation buoys are attached to the hose. The hoses are maked for easy identification and are equipped with navigation lights.

The hoses will have a normal working pressure of 200 psi and a burst rating at least five times that. The hoses float freely about the SPM when not in use; however, by USCG regulations, they must be flushed with seawater after use if they are not to be used within 7 days of the previous transfer. When a hurricane is predicted for the port site, the hoses must be flushed with water and the PLEM isolation values closed 36 hours before the storm is due.

2. Single Point Mooring. Two types of SPMs which allow the tanker to rotate about the mooring were mentioned above: the catenary anchor leg mooring (CALM) and the single anchor leg mooring (SALM). As described in Section 2.1, many other types of SPMs exist or are planned for DWPs, however, consideration here is limited to these two. These and their components were described in detail in Sections 2.1.2.1 and 2.1.2.2, respectively, and will not be discussed further here.

3. Pumping Platform Equipment. All of the equipment found on the pumping platform is standard for oil transfer systems in which custody transfer takes place. The selection of specific manufacturer's designs will be based on criteria similar to those of any other oil transfer system: designed throughput rate, reliability, cost, and applicability.



ITEM	NAME	MATERIAL OR NOTE
1	Liner	Nitrile, C. P. Rubber
2	Breaker	Nylon, Rayon, Cotton, Steel, Rubber Impregnated
3	Reinforcing Plies	Textile or Steel, Rubber Impregnated, Counter Wound
4	Helical Wire	Steel-3/8" Dia. to 5/8" Dia.
5	Filler Material	Nitrile, S. B. Rubber, Natural Rubber
6	Outer Cover	Neoprene, Polyurethane

Figure 2-23. Hose Construction Details
Source: Reference 4

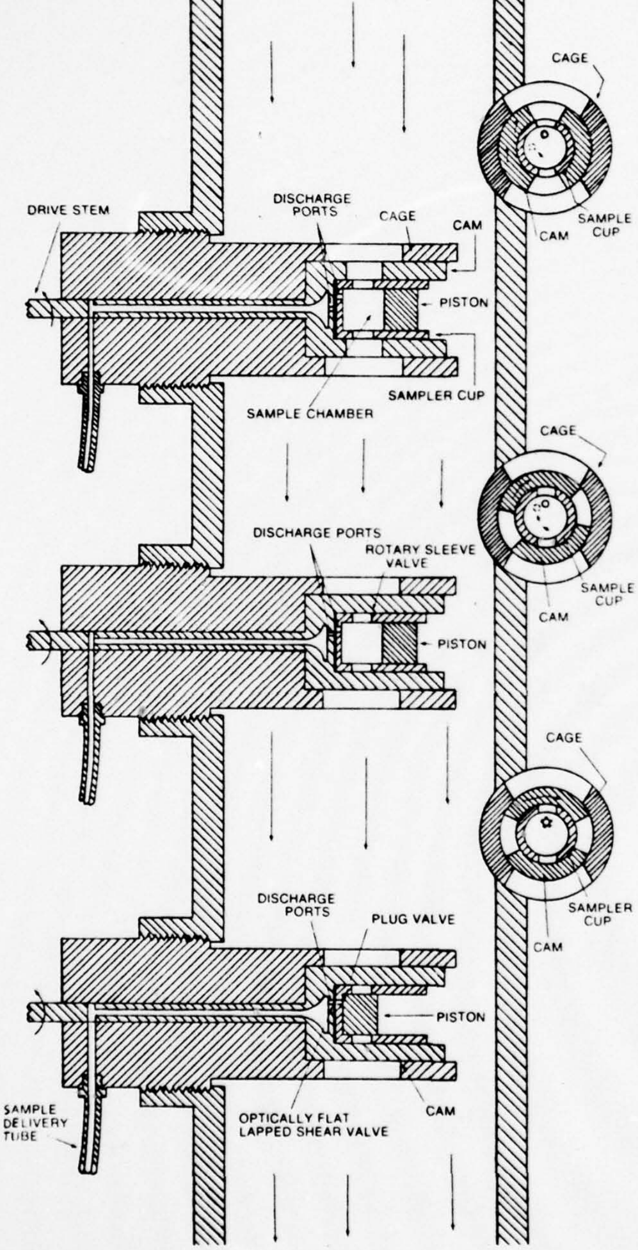
The samplers used will be installed in the main oil lines. They operate continuously and collect small samples at predetermined intervals. The sampling interval is determined by the number revolutions the sampling cup makes between open periods. Figure 2-24 illustrates the sampling principle for one sampler design. These samples are analyzed chemically for determination of crude oil grade, density, etc.

Upstream from the pumps, strainers and air eliminators are installed. These serve to minimize the amount of solid particles and gas bubbles that reach the pumps. A strainer consists of a cylindrical basket mounted in the oil line. Inside the basket is a screen designed to catch solid particles which may be present in the oil line. Figure 2-25 illustrates the principle of a strainer. There is usually a small drain line (2") to facilitate maintenance and some are equipped with differential pressure gauges on either side of the device to signal when the screen needs cleaning.

The air eliminator is a vertical or horizontal chamber with a vent at the top through which trapped gases in the oil stream may escape. The opening and closing of the vent is controlled by float switches which indicate the fluid level. Figure 2-24 illustrates an air eliminator. The chamber is equipped with a drain line for maintenance.

When positive displacement meters are used for custody transfer, strainers and air eliminators may be used immediately upstream to protect them.

The pumps used on the platform are high volume, multiple stage centrifugal pumps. They have detectors for excessive bearing vibration, adequate lubrication and excessive casing pressure. The detection system has a two-stage alarm such that when one parameter goes out of bounds: first, an alarm is sounded at the control console and, second, if the condition does not improve, the pump is shut down. Drain lines and lines for the seal coolant are provided for maintenance and operation. Maintenance is required on a regular basis for the bearings, seals, and the detection system. The dimensions of the pump, its casing,



STEP 1

FILL

A series of three sets of ports provide entrance to the sample cavity. The ports in the cage and sample cup are always lined up with each other and with the axis of flow in the pipe. There is no relative movement between these two ports. The ports in the cam (cup remains stationary) are aligned with the cage and cup ports by counterclockwise rotation of the drive stem. In this position in the cycle, the sample cavity is open to the line and is continuously filled and flushed by the fluid flowing through it.

STEP 2

ISOLATE

The sample is isolated in the sample cup by the rotary sleeve valve action of the ports in the cam rotating beyond the ports in the sample cup. A sample has thus been captured isokinetically in its natural state of flow in a volumetrically precise and repeatable quantity.

STEP 3

EJECT

Further rotation of the cam brings into alignment the two discharge ports of the optically flat, lapped shear valve at the bottom of the sample cup. Line pressure behind the piston ejects the sample through the shear valve, into the delivery line, and to a sample receptacle or analyzer. NOTE: Pressure is equalized across all sample leakage paths except the hardened, shear valve surface thus assuring a precise volume of sample. At the completion of the piston stroke, ejecting the sample, a plug on the bottom of the piston seals the shear valve port until the shear valve closes. Further rotation of the cam lifts the pressure equalized piston and opens the sample cavity to line flow completing the cycle of operation.

Source: Clif Mock Co.

Figure 2-24. Automatic, Continuously Operating Sampler

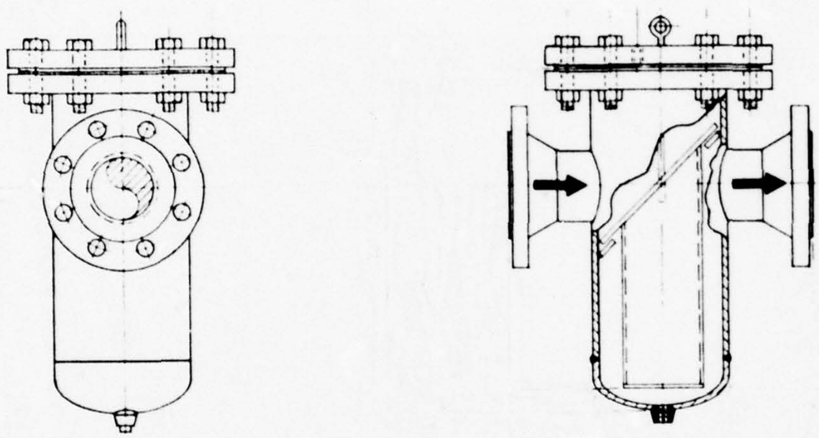
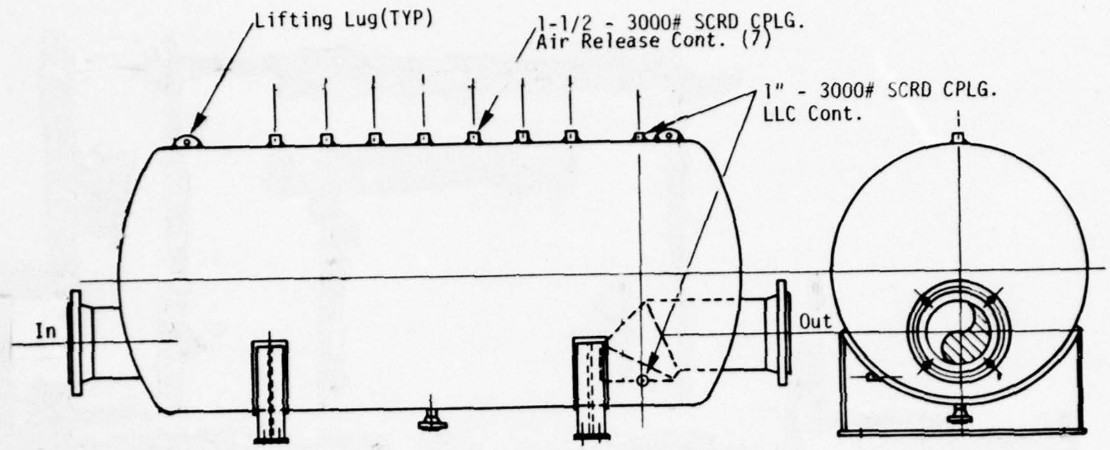


Figure 2-25. A Typical Vertical Basket Strainer
Source: WEAMCO



Notes:

1. Design: Flanged 150# R.F. Inlet - Outlet
2. Design: 275 PSIG 100°F
3. Designed per ASME Boiler and Pressure Vessel Code, 1974 Edition
4. Mat'ls of Construction: All Carbon Steel

Figure 2-26. An Example of a Horizontal Air Eliminator
Source: WEAMCO

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and other components depend on the pump type and volume. Consequently, the sample diagram provided in Figure 2-27 is representative of only one type of pump which might be used.

For critical electrical equipment, standby generators are required in case electrical power is lost from the main supply source. For the hydraulic fluid pumps, gas-driven generators may be used in emergency situations.

The meters used for custody transfer on the DWP are turbine flow meters. Figure 2-28 is a Daniel PT Meter System. Fluid passing through the meter causes the rotor to revolve with an angular velocity proportional to the flow. The rotor blades, passing through the magnetic field of the pick-up, generate a pulsing voltage in the coil of the assembly. Each voltage pulse represents a discrete volume. The total number of pulses, integrated over time, represents the total volume metered. An alternative is a positive displacement meter which is much more expensive and requires more maintenance.

Each individual meter is calibrated with a prover such as the one shown in Figure 2-29. The prover functions by measuring the time required for a spheroid to travel the prover loop which is of known volume and comparing this to the volume calculated by the turbine meter. From this a meter factor is determined for each meter.

Each oil line is equipped with a scraper launcher on the platform so that cleaning pigs can be passed through the lines as required. A launcher consists of a chamber with one hinged end, an inlet from the oil line, and an outlet line. A schematic of a typical launcher is shown in Figure 2-30. Pigs are loaded into the chamber, the lid secured, and the isolation valve opened to direct the flow to the launcher. The pig is carried by the oil in the line. A drain line is provided for maintenance purposes.

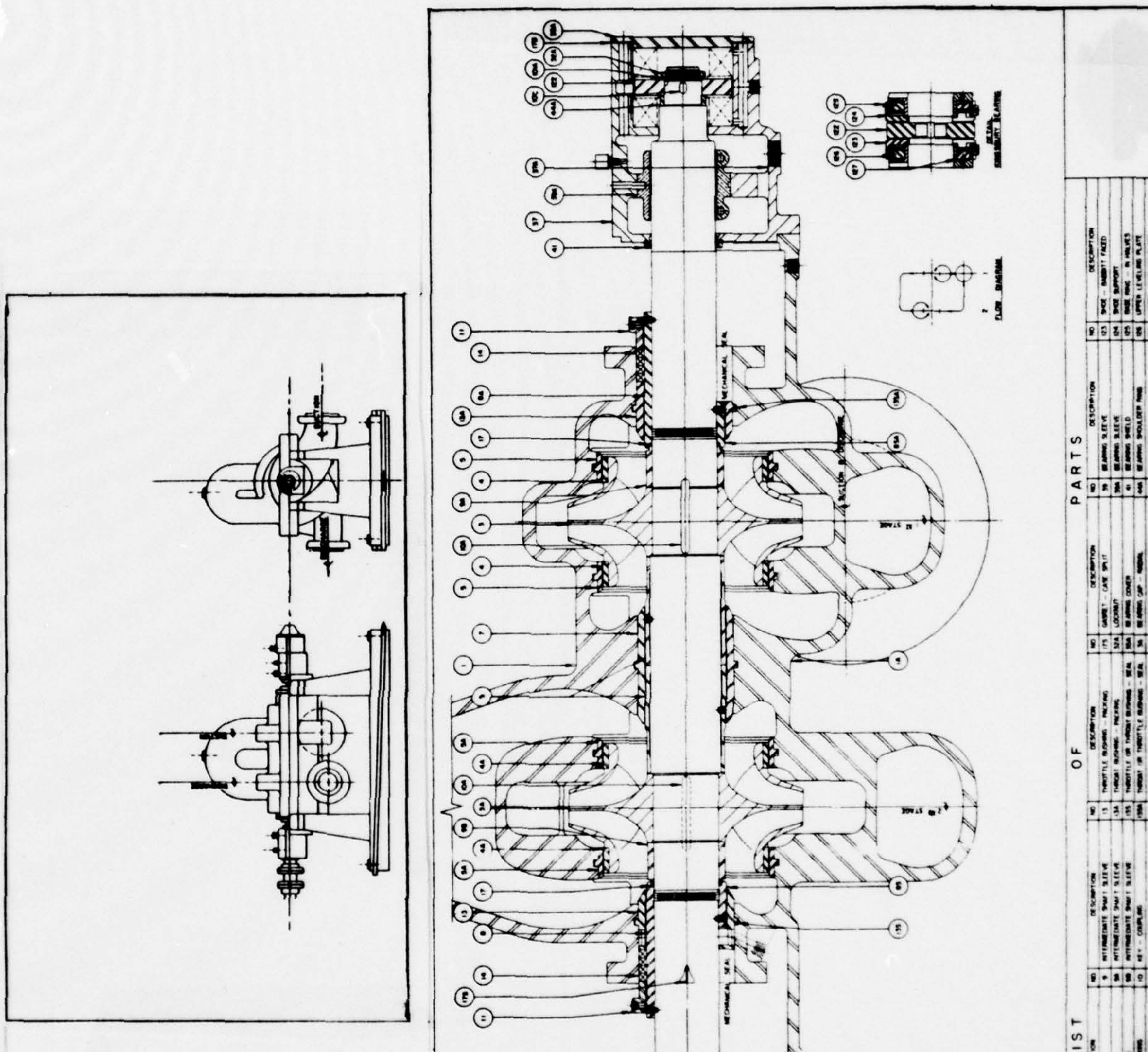
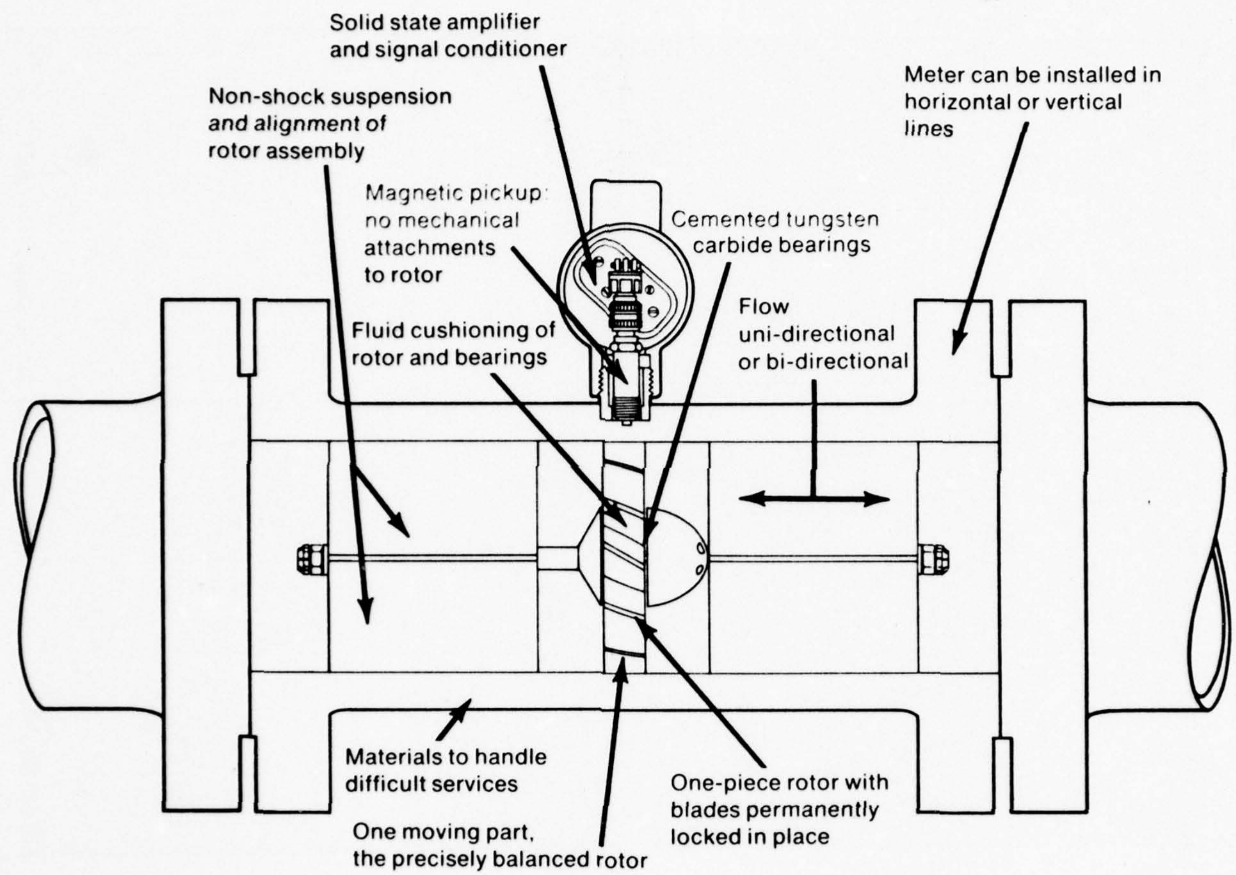


Figure 2-27. Oil Pipeline Pump
Source: United Centrifugal Pumps



Source: Geosource Inc.

Figure 2-28. Turbine Flow Meter

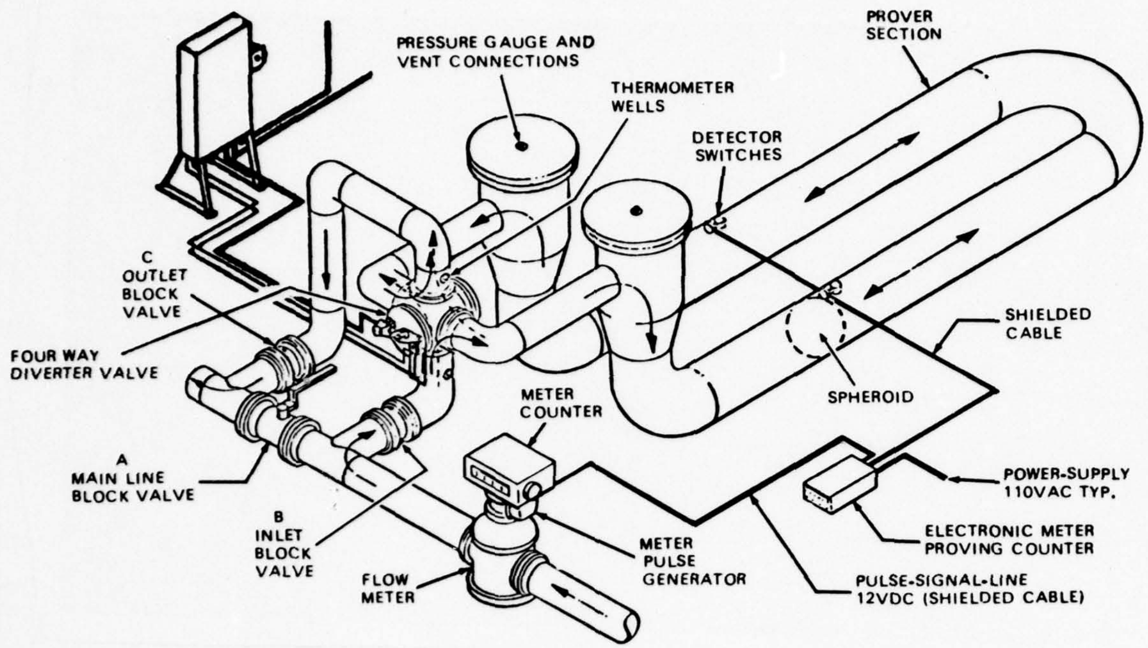


Figure 2-29. A Meter Prover

Source: Geosource, Inc.

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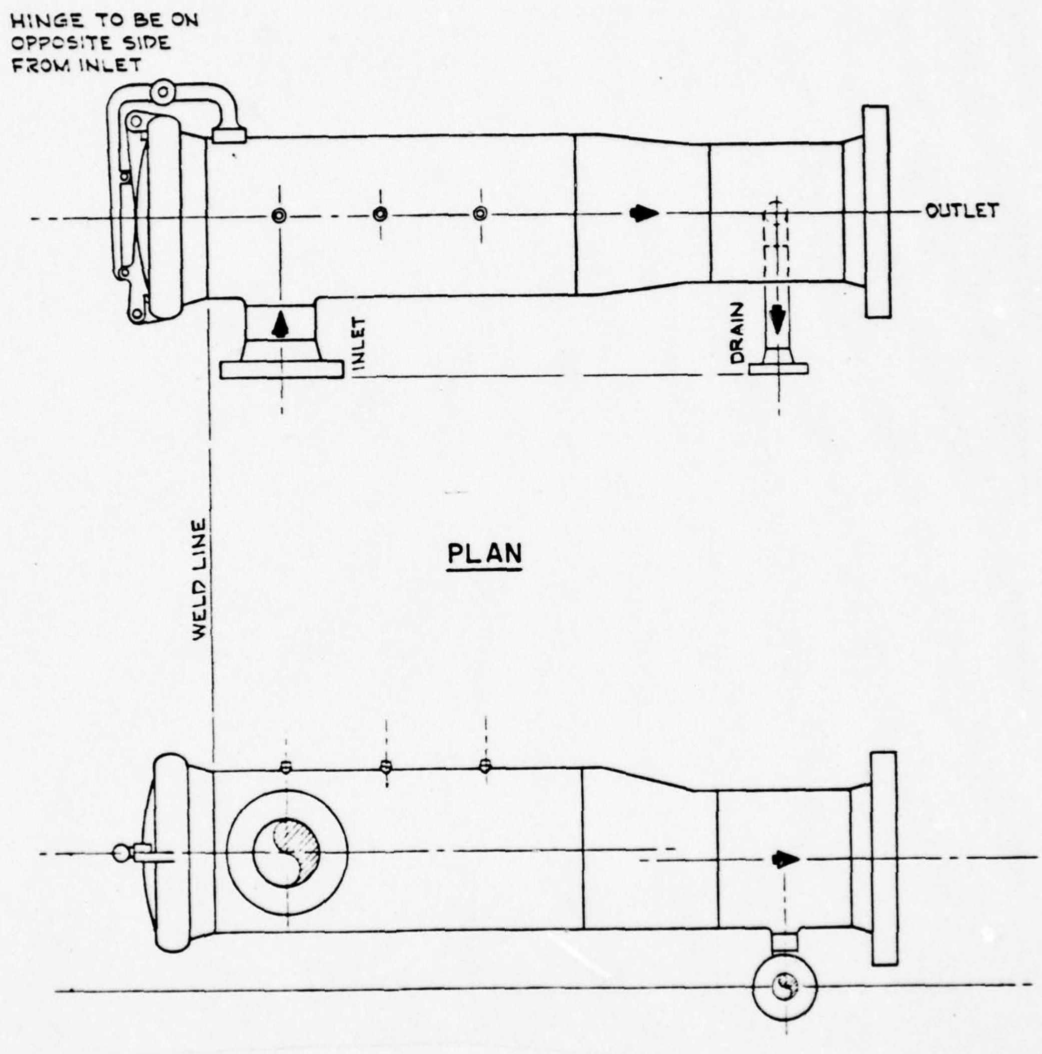

Figure 2-30. An Example of a Scraper Launcher Trap
Source: Butler Associates, Inc.

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3.0 OIL SPILL RISK ASSESSMENT

3.1 MALFUNCTION AND SPILL DATA FOR DEEPWATER PORTS

Monobuoy and other mooring systems to handle deep draft ships offshore have been in use for over 17 years. As mentioned in Section 2.2 there are at present over 150 operational SPMs around the world. Unfortunately, there has been in the past no uniform and concerted effort throughout the industry to assemble and document malfunctions, oil spills and other problems. However, during the last three to four years such an effort has been initiated, primarily under the auspices of the OCIMF. In particular, an extensive study of problems with floating hoses encountered by SPM operators was undertaken. The result has been a more general recognition by the operators of the importance of quality control during hose manufacture and of the use of proper techniques for handling and storage of hose segments and strings. Although the OCIMF provides a means for SPM operators to discuss mutual problems and experiences, the operating practices and exchange of data is a matter of individual choice. Hence there is little "hard" data to serve as a basis for assessing the performance of a general SPM or deepwater port.

In spite of this situation it is useful to collect what data and information have been released by individual industries in order to perceive what the problem areas are and what kind of spill hazards are to be anticipated. Some oil spill data have been made public:[3] (1) ECO, Inc. (via the SPM Form of the OCIMF); (2) Shell Oil Company's tally of spills at its SPM at Durban, Union of South Africa, reported to the House of Lords (U.K.) during hearings on the Anglesey terminal; spillage from Shell Oil Company SBM terminals through October 1971, reported by the Anglesey Defense Action Group, and a submittal from Exxon on four SPM installations. These data reflect experience prior to 1973. Also these same data have been reported in a number of different references. In addition to these data, representatives of several terminal operators have discussed informally their operating experience, especially the occurrence of oil spills.

In the following paragraphs these data are utilized to develop some statistics regarding the frequency of oil spills at SPMs and to identify important failure modes.

For convenience the Shell-Anglesey, Shell Durban and the ECO data are repeated here in Tables 3-1, 3-2, 3-3, and 3-4. The Shell-Anglesey data are shown in a somewhat different manner than in the past. Shown in the fifth column of the tables are the number of operational SPM-years, which is the product of the number of SPMs and the number of years each has been in operation. The seventh column lists the number of spills divided by the number of port calls, the frequency of spills per loading or offloading operation. As will be noted, the "Durban" spills shown separately in Table 3-3 are included in Table 3-1. The former table shows that out of the total of 23 spills, only 13 resulted from a failure or operational error associated with the SPM itself or the oil transfer system. The remaining 10 spills resulted from some mishap associated solely with the tankship such as a hull leak or a mistake made by the tankship's crew in allowing a cargo tank to overflow. This suggests that not all of the spills at the other locations listed in Tables 3-1 and 3-2 were associated with the oil transfer system or the SPM. However, there is no clarifying information regarding this except to note that operators of conventional oil transfer terminal usually claim that the majority of oil spills during loading or offloading are from the ship. In Table 3-1, only the 13 SPM-associated spills for Durban are included. For lack of better information, the spills at the other terminals are assumed to be associated only with the SPM or the oil transfer system.

The values of spills per port call have been plotted versus SPM-years in Figure 3-1, combining both offloading and loading ports. As might be expected, this plot indicates that the frequency of spills decreases with experience. Indeed, after approximately 10 SPM-years, the frequency of spills levels out at about 0.02 spills per ship call. As will be shown subsequently in Section 3.2, this frequency is not significantly different than the spillage rate experienced at conventional oil transport, marine terminals.

Table 3-1

FREQUENCY OF OIL SPILLS AT DISCHARGE SPMs (SHELL ANGLESEY DATA)

Location	No. SPM	Years Operational	Port Calls	SPM Years	No. Spills	Spills per Port Call
Yokkaichi	2	6	514	12	8[a/]	0.016
Niigatu	1	5	104	5	15[a/]	0.144
Kawasaki	1	3	194	3	24[a/]	0.124
Durban	1	1	91	1	13[b/]	0.143
Port Dickson	1	8	583	8	3	0.005
TOTALS OR AVERAGE	6	23	1486	29	61	0.041

[a/] All less than 150 gal.

[b/] Involving oil transfer system only.

Source: Reference 3.

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Table 3-2

FREQUENCY OF OIL SPILLS AT LOADING SPMs (SHELL ANGLESEY DATA)

Location	No. SPM	Years Operational	Port Calls	SPM Years	No. Spills	Spills per Port Call
Gamba	1	$4\frac{7}{12}$	303	4.58	23	0.076
Forcalos Nigeria	2	2	533	4	23	0.043
Mina-al-Fahal Muscat, Oman	3	4	1676	12	9	0.0005
Halul Island, Qator	1	$9\frac{7}{12}$	816	9.58	9	0.011
Miri, Sarawak	3	10	2250	30	44	0.020
TOTALS OR AVERAGE	10	$30\frac{1}{6}$	5578	60.16	108	0.019

Source: Reference 3.

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Table 3-3

LISTING OF FIRST 23 DURBAN SPILLS

	Date	Amount	Time to Discovery (minutes)	Cause
1	21.9.70	20	10	Bolts on 16" blind flange loosened
2	29.9.70	250	nil	Tanker hull leak, no. 5 port wing tank
3	30.9.70	85	5	Underwater hose leak, manufacturer's defect
4	4.10.70	6	nil	Spill from hose end during connect operation
5	10.10.70	1	nil	Underwater hose leak, manufacturer's defect
6	11.10.70	20	nil	Tanker ballast discharge valve leaking
7	18.11.70	1,470	nil	Floating hose rupture at buoy, manufacturer's defect
8	12.12.70	2,940	nil	Hull leak due to contact with SBM ballast box
9	22.12.70	42	nil	Underwater hose nipple, manufacturer's defect
10	3.1.71	24	5	Tanker "World Friendship" overboard discharge
11	31.1.71	85	5	Tanker "World Friendship" overboard discharge
12	6.2.71	4,410	nil	Butterfly valve shut against ship pumps blowing 24" deckline out of expansion joint
13	16.2.71	2,940	nil	Both end hoses parted when mooring lines broke in 40 knot squall, light condition
14	17.2.71	20	nil	During repair due to spill 13
15	18.2.71	20	nil	During repair due to spill 13
16	27.3.71	20	nil	Hose connection during heavy rain
17	31.3.71	880	nil	Floating hose nipple blew during discharge
18	6.5.71	1	5	Tanker hull leak, no. 2 port wing tank
19	15.5.71	20	5	Main sea valve leak, port pumproom
20	22.5.71	1,470	2	Main sea valve leak
21	14.6.71	620	nil	Tanker overflow from no. 3 starboard tank during discharge
22	11.7.71	72	nil	Tanker overflow from no. 1 port wing tank during discharge
23	24.10.71	600	nil	Floating hose rupture, ship end. Manufacturer's defect

Source: Reference 3.

TABLE 3-4

OFFSHORE TERMINAL SPILLS OBTAINED FROM SBM FORUM (via ECO, Inc.)

Year Installed	Port	Type	Maximum Tanker Size	Spill Size, Gallons	Report Period	Cause
62	Brega	Fixed	100	33,600	62-72	Unloading arm
62	Brega	Fixed	100	21,000	62-72	Unloading arm
62	Brega	Fixed	100	8,400	62-72	Unloading arm
62	Brega	Fixed	100	16,800	62-72	Unloading arm
62	Brega	Fixed	100	4,200	62-72	
69	Brega	SALM	300	2,100	69-72	Hoses
70	Singapore	CALM	250		70-71	
71	Nakagusaku	SALM	250		71-72	
72	Botany Bay	SBM	80	1,260	72-72	Expansion piece
67	Huelva Bay	SBM	100	25,200	71-72	Mooring line and hose
67	Huelva Bay	SBM	100	420	71-72	Hoses
67	Huelva Bay	SBM	100	840	71-72	Hoses
67	Koshiba	SBM	100	21,000	67-72	Fishing vessel tore hoses
67	Koshiba	SBM	100	840	67-72	Hoses
67	Koshiba	SBM	100	420	67-72	Hoses
71	Tetney	SBM	210	25,200	71-72	Tanker hit buoy
71	Tetney	SBM	210	200	71-72	Hoses
71	Tetney	SBM	210	400	71-72	Hoses
70	Durban	SBM	220	8,400	71-72	Underbuoy hose
70	Durban	SBM	220	1,680	71-72	Hoses
70	Durban	SBM	220	420	71-72	Hoses
68	Wulsan	SBM	200	420	71-72	Hoses
68	Wulsan	SBM	200	630	71-72	Hoses
65	Gamba	SBM	90	420	67-72	Hoses
65	Gamba	SBM	90	6,300	67-72	Underbuoy hose
65	Gamba	SBM	90	200	67-72	Hoses
72	Porto Baleo	SBM	100		72-72	
72	Porto Baleo	SBM	250		72-72	
66	Wulsan	SBM	75	840	70-72	Hoses
66	Wulsan	SBM	75	600	70-72	Hoses

TABLE 3-4 --Continued.

Year Installed	Port	Type	Maximum Tanker Size	Spill Size, Gallons	Report Period	Cause
65	Chiba	SBM	120	2,520	70-72	Buoy chain
65	Chiba	SBM	120	400	70-72	Hoses
65	Chiba	SBM	120	600	70-72	Hoses
68	Kawasaki	SBM	260	2,100	70-72	Buoy hit by vessel
68	Kawasaki	SBM	260	840	70-72	Hoses
68	Kawasaki	SBM	260	200	70-72	Hoses
71	Java	SBM	80	1,050	71-72	Swivel seals
71	Java	SBM	80	400	71-72	Swivel seals
72	Java	SBM	140		72-72	
63	Port Dickson	SBM	100	7,140	70-72	Hoses
63	Port Dickson	SBM	100	400	70-72	Hoses
63	Port Dickson	SBM	100	200	70-72	Hoses
63	Port Dickson	SBM	100	800	70-72	Hoses
64	Miri	SBM	65	400	70-72	SBM hose connection
64	Miri	SBM	65	600	70-72	Hoses
71	Seria	SBM	250		71-72	
67	Subic Bay	SBM	108	400	70-72	Valves
67	Subic Bay	SBM	108	1,000	70-72	Hoses
70	Saint John	SBM	350	200	70-72	Chafed underbuoy hose
70	Saint John	SBM	350	400	70-72	Chafed underbuoy hose
70	Saint John	SBM	350	200	70-72	Chafed underbuoy hose

Source: Reference 3.

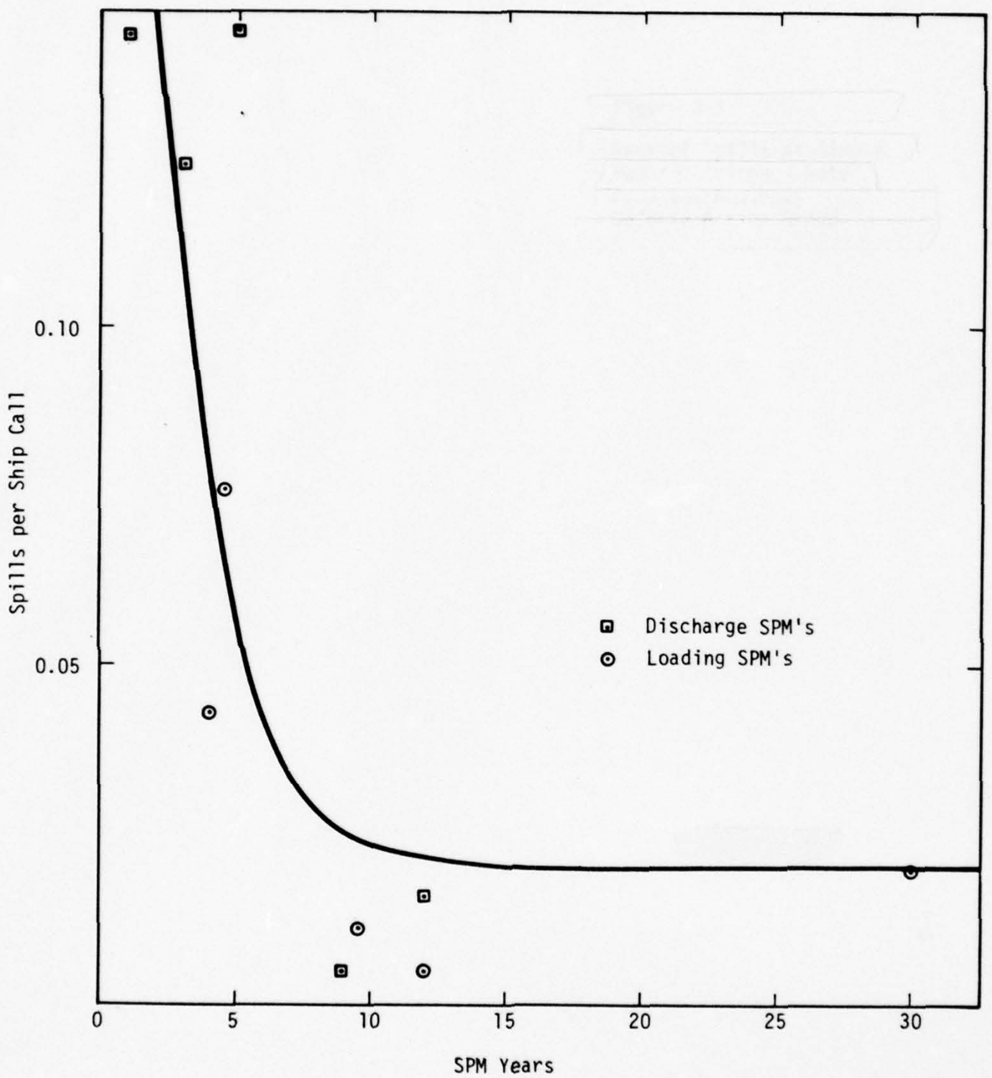

Figure 3-1. Rate of Spills at Single Point Moorings - Data from the Anglesey Defense Action Group

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Also, Figure 3-1 indicates that the spill frequency is about the same for both loading and offloading ports. However, this is somewhat misleading. The original Shell-Anglesey data as reported in Reference 3 also listed volume of oil spilled. In summary, the average spillage volume (total volume spilled divided by the total number of ship calls) is 0.33 bbls per ship call for offloading ports versus 10.6 bbls per ship call for loading ports. The reason for this difference between volumes spilled at loading and offloading ports is not known with certainty. However, the experience of some terminal operators indicates much of the difference may result from accidents at loading ports in which one or more cargo tanks overflow. Such a mishap does not involve the integrity of the oil transfer system but is a matter of control and proper operating procedure.

The spillage frequency of 0.02 spills per ship call derived above must be viewed with caution. First, it reflects the experience of a single oil company. The spillage experience at the SPMs of other companies could be considerably better or worse. Second, the criteria for reporting spills and their inclusion into the list is unknown. The spills reported by some terminals in Table 3-1 and 3-2 were no more than 250 gals whereas other operators reported only a few large spills much greater than 150 gal, but no small spills. Third, as already noted, the source of the spills is not known and only some actually may be associated with the oil transfer system. Fourth, the spillage rate reflects practices prevalent during the 1960s, especially the later years of that decade.

Nevertheless, this frequency of spillage was used as the basis for the quantitative assessment of the risk of oil spills to be presented subsequently in Sections 3.3 and 3.4. Although knowledgeable industry representatives have claimed that operating procedures and inspections, recently introduced, have greatly reduced the frequency of spills, the above derived value still represents at least a potential risk of spills.

The SBM Forum data in Table 3-4, together with the "Durban" data were used to help identify the major causes of spills. The Forum's data

lists 45 incidents of which 40 were spills from SPMs with floating hoses. These data, together with the "Durban" data have been aggregated in Table 3-5 by cause or source of the spill. Assuming that the combined sets of data represent a random sample, 79 percent of SPM spills result from various problems with either the floating or underbuoy hoses. The remaining causes and sources of spills include leaky valves, failure of the mooring line (breakout), a vessel hitting the buoy and rupture of an expansion joint in the tanker's product lines.

Further breakdown of hose failures by cause is not possible using available information. In their study of hose failures, Southwest Research Institute (SWRI) obtained via a questionnaire a breakdown of the reasons why operators replaced hose segments or hose strings.[4] The reasons were aggregated into seven categories:

1. Hose Fracture or Breakage - fatigue, excessive internal pressure, bending, excessive tensile load and being struck by a boat;
2. Nipple Leak - weakened nipple-liner bond and tearing of liner just beyond the nipple;
3. Nipple Pull-Out - ship breakout and broken binding wires;
4. Kinking (and Delayed Fracture) - mishandling, severe environmental forces (e.g., first off buoy or rail hoses);
5. Liner Collapse - Poor adhesion, oil penetration and excessive vacuum;
6. Abrasion of Covers (Delayed Failure) - Rubbing on sea floor, hoses rubbing on each other and rubbing on some other object (e.g., ship and buoy);
7. Failure of Flotation Material - damage by ship's propellers, chain dragging, etc.

The number of replacements as reported by SWRI are listed in Table 3-6, which aggregates the data for the three types of hoses—first off buoy, rail and mainline. Table 3-6 also distinguishes whether or not the problem leading to replacement was associated with the area at or near the nipple-hose junction. Sixty percent of all hose problems occurred at this location. The nipple-hose connection,

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Table 3-5

SPM SPILL DATA AGGREGATED BY
CAUSE OR SOURCE OF SPILL

	SBM Forum Data	Durban Data	Total	Percent of Total
Hoses and Connections Leaked	31	10	41	79
Valves Leaked	1		1	2
Swivel Seals Leaked	2		2	4
Vessel Hit Buoy	2		2	4
Rupture of Expansion Piece in Tanker Oil Pipelines	1	1	2	4
Buoy Chain Failure	1		1	2
Mooring Line Failure (Breakout)	1	1	2	4
Blind Flange Leak	—	1	1	2
TOTAL SPILLS	39	13	52	101[a]

[a] Does not total 100 because of rounding.

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Table 3-6

HOSE FAILURES - REASONS
FOR REMOVAL FROM SERVICE

	Reason	Number of Failures	Percent of Total	Number at Nipple	Percent at Nipple
1.	Fracture-Rupture	103	41.6	84	81.6
2.	Nipple Leak	40	16.1	40	100.0
3.	Nipple Pull-Out	2	0.8	2	100.0
4.	Kinking	43	17.3	12	27.9
5.	Liner Collapse	28	11.3	9	32.1
6.	Cover Abrasion	13	5.2	1	7.7
7.	Flotation Failure	19	7.7	0	0
	TOTAL	248	100.0	148	59.7

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as pointed by the SWRI study, is especially subject to much bending and fatigue and hence it is reasonable to expect a relatively large number of problems there.

Presumably the first three reasons listed involved leakage. It is not clear, from the reported data, that leakage was an immediate factor in the other four reasons for hose removal. However, it is likely that if the hoses with the last four types of problems were left in service too long, leaks would eventually develop. For example, a kinked hose will suffer extra bending and fatigue at the location of the kink, and as a result, the re-enforcing wire may break or the liner may collapse and break. The former, in turn, could eventually result in penetration of the hose by the broken wire; in the latter case, oil will eventually leak through the tear in the linear and through the outer layers of the hose.

The data presented above generally conforms with the more qualitative impressions of industry representatives. They concur that hoses give 80 to 90 percent of the problems. These problems are not necessarily spills but various types of damage, such as the loss of flotation or a kinked hose, which lead to operational difficulties. The remaining 10 to 20 percent of the problems are felt to be divided between failures of other components and human errors.

One representative stresses the problems with the mooring hawsers. High cyclic loads, caused by movement of the buoy and ship at different frequencies, led to fatigue, decreased strength and, finally, failure of the hawser. Presently there is no monitoring system in use which can detect the extent of fatigue and loss of strength in the hawser. Some companies favor using a single, large diameter hawser instead of two smaller ones. The reason for this is that ships often undergo an oscillating yawing motion, such that the full mooring load is imposed alternately on each hawser, especially if the ship's fairleads are rather far apart.

Representatives of the OCIMF feel that many hose problems have been greatly reduced or eliminated. Many of the failures which have occurred in the past (and, by implication, are reflected in the spill data

in Tables 3-1, 3-2, and 3-3) are much less prevalent today. This has come about through improved handling and storage of new hoses (a problem recognized in the SWRI study), improved inspection and quality control during manufacture and better testing methods.

These representatives state further that for the CALM buoy, the first hose off the buoy has the worst service life because of the wave induced bending moments and fatigue. This, of course, depends on the sea states at the buoy location, and in some isolated locations this hose has lasted 3 to 4 years. However, as a rule of thumb, one company replaces this hose every 8 to 9 months. Hoses in the floating string are not subject to many problems anymore. Several companies pressurize the hose strings with air in order to reduce bending and improve the manner in which the hoses ride the waves. This also aids in inspection of the hoses for leaks since escaping air bubbles are relatively easy to see. The same company, as above, replaces the hose string every 18 months as a rule. Rail hoses are built to be more flexible than the others, but nevertheless are subject to considerable chafing and kinking. The later may reduce throughput, but rarely contributes to pollution unless the kinked condition is ignored by the operator. Submarine hoses have a low failure rate and are easily inspected by divers. The same company as above recommends replacement every 12 to 15 months.

The prevalence of hose leaks close to the nipple, especially leaks through failed areas of the bonding between the hose and nipple, have been substantially reduced in recent years. High standards for the construction of this part of the hose have been emphasized by OCIMF and most companies require from the manufacturer careful attention and good quality control over the hose-nipple bond. Pressure tests help to detect failures before installation. Also, keeping the hose pressurized between ship calls helps to reduce fatigue in this area and makes leak detection, prior to pumping oil, easier.

At some SPM locations float-sink hoses are used. These generally are used in locations where ship traffic is heavy, such as in Tokyo Bay, Japan. When not in use, the hoses are sunk to the bottom so they will

not interfere with surface traffic. One such installation has been operated by the U.S. Navy at Koshiba in Tokyo Bay since 1967. The SPM is a CALM type (IMODCO) having three hoses: two 12-inch cargo hoses and a center 12-inch hose containing two 2-inch air line and one 4-inch water line. Both the air lines and the water line are connected to two hollow buoys at the outboard end of the hoses. To sink the hoses, water is pumped into both the buoys and the available space in the 12-inch hose containing the air and water lines. To raise the hoses, air is pumped into these spaces. This hose string is 600 feet and the CALM buoy is approximately one-mile offshore.

During the ten years of operation the principal problems encountered have been damage to the float-sink and underbuoy hoses caused by fishing vessels and bottom currents (both natural and those caused by passing vessels). The damage has consisted of severe chafing and slashing (from anchors, fishing lines, fishing nets, etc.) The latter occasionally resulted in a spill when the hoses were left full of product. A former executive officer of the facility reported that they experience many leaks (1/2 to 2/3 of all leaks) through the flange seals between hose segments.[5] These were cured by tightening the flange bolts. They did not perform a pre-pressurization test prior to flow of product through the hoses. Leaks were detected by visual observation. Although not a cause of spills, corrosion was a continual maintenance problem for the buoy and the bolts fastening the flanges of the hose segments.

3.2 HISTORICAL SPILL DATA ON OIL TRANSFER OPERATIONS

This section reviews accidents and spills that have occurred during off-loading and transport of oil in more conventional equipment. The purpose is to elucidate the types of accidents and equipment failure modes, most of which will be applicable, in some degree, to deepwater ports. Another purpose is to develop the frequency of certain types of accidents, which will be directly applicable to the Oil Transfer System of deepwater ports. First, data on the types and causes of spills during loading or discharge of bulk liquid cargoes is reviewed. Second, statistics on spills from liquid pipelines, both terrestrial and underwater in the Gulf of Mexico Outer Continental Shelf will be discussed. Third, data pertaining to accidents and spills of oil from offshore oil production platforms, also in the Gulf of Mexico, will be reviewed.

Table 3-7 lists the number of polluting incidents by cause during the loading or offloading of tankships in all U.S. ports during 1974 and the first eight months of 1975. The data were extracted from the data tape of U.S. Coast Guard's Pollution Incident Reporting System (PIRS).[6] Most of the spills, 89 percent, occur from the tankship, and of these the single most frequent cause is tank overflow, 35 percent of the spills from the tankship. Presumably, most of these spills occurred during loading operations. The next ranking cause is the failure, rupture or leak of various types of equipment, 29 percent of spills from the tankship. For spills from the failure of terminal equipment, leaks and ruptures are the leading causes, amounting to 55 percent of spills from the terminal. Various personnel errors, including bilge or ballast pumping cause 16 percent and 25 percent of the spills from the ships and the terminal, respectively.

Figure 3-2 shows the distribution of spill size with the number of spills for the PIRS data. It may be noted that most of the spills were small, the median being only 0.5 bbls. Only 8 of the spills, 1.4 percent, were greater than 100 bbls. By cause, Cargo Tank Overflow accounted for 3 spills over 100 bbls, Valve-Pump Failure accounted for 2 spills over 100 bbls, and the Unknown cause category accounted for 3 spills over 100 bbls. The largest spill, in the range 1000-3000 bbls also was in the last category.

Table 3-7

CAUSES OF OIL SPILLS ASSOCIATED
LOADING AND OFFLOADING TANKSHIPS
AT MARINE TERMINALS

(All U.S. Ports, 20 months during 1974-1975)

Cause Cause	Number of Spills at Terminal	Number Spills from Ship
Tank Overflow	10	212
Unknown	4	96
Valve-Pump Failure	5	73
Pipe-Hose Rupture or Leak	22	51
Other Equipment Failure	11	51
Improper Hose Handling or Valve Operation	8	37
Other Personnel Error	9	58
Hull Leak	--	23
TOTALS	69	607

Source: USCG Pollution Incident Reporting System.

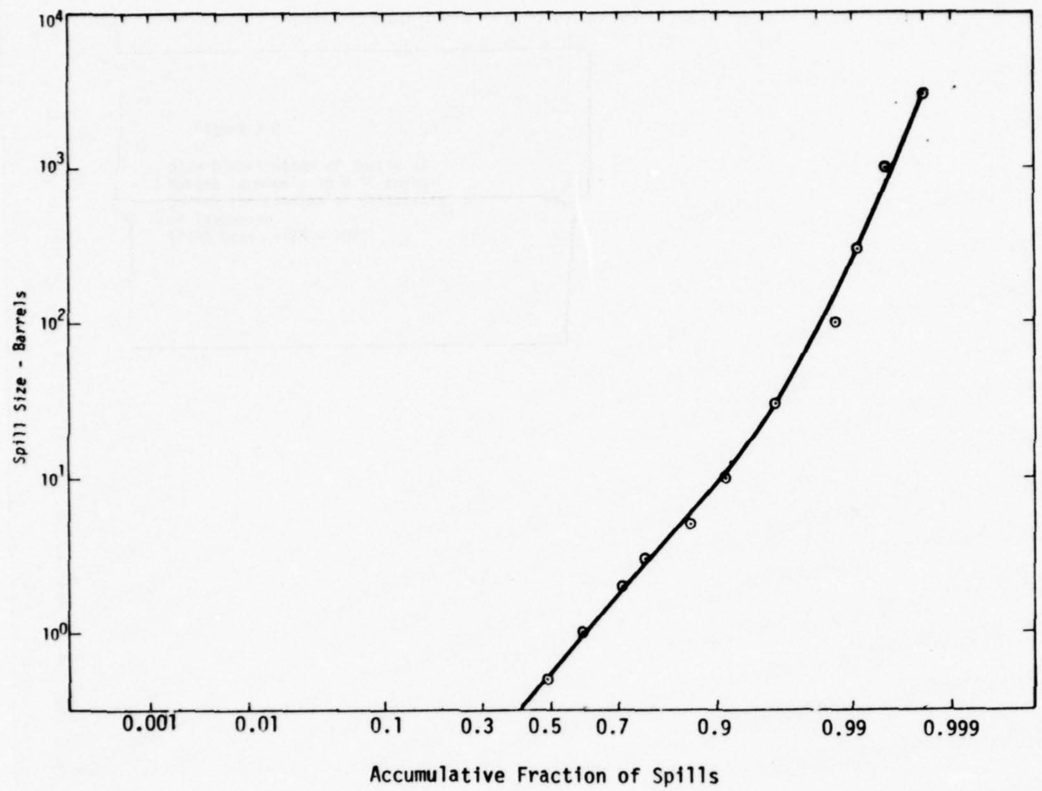

Figure 3-2. Size Distribution of Spills at Marine Terminals in U.S. Ports During the Loading or Offloading of Tankships (PIRS Data, 1974-1975)

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The frequency of cargo tank overflow spills, together with their relatively large size seems to support the contention that such accidents contribute significantly to the poorer spill record of loading type SPM terminals.

According to the data in Table 3-7 a total of 655 spills occurred during the loading or offloading of tankers in U.S. ports over the 20-month period covered. Based on data from the U.S. Army Corps of Engineer Report, Waterborne Commerce in the United States,[7] it was estimated that there were approximately 33,000 tankship trips annually into U.S. ports for the period of 1974 to 1975. Assuming that for each trip only one stop is made in a port to load or offload bulk liquid cargo, then it is estimated that there were approximately

$$33{,}000 \times \frac{20}{12} = 55{,}000$$

tankship loading-offloading operations in U.S. ports during the 20-month period covered by the spill data. Therefore, it is further estimated that the spill frequency during these operations is

$$\frac{676}{55{,}000} = 0.012 \text{ spills/port call.}$$

Within the accuracy of the data used, this spill frequency is essentially the same as that at worldwide SPMs.

Similar data are available for the port of Milford Haven, U.K. Reference 16 gives the following data

Year	1961	1964	1967	1970	1973
Total number of spills	45	43	55	56	50
Number of ships	1,066	1,392	2,680	3,359	3,886
Spills per port call	0.042	0.031	0.021	0.017	0.013

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The same reference states that approximately 75 percent of the spills are from the tankship. In contrast to U.S. ports only 19 percent of the spills result from overfilling cargo or bunker fuel tanks. The major causes are "Bilges/Ballast"--26 percent; "Hull Defects"--24 percent; and "Sea Valve"--21 percent. From the terminal the major causes of spills are the "Pipeline Hoses"--48 percent and "Sumps/Slop Tanks"--23 percent. The lower incidence of tank overfill accidents may be a result of the port's heavier usage for the offloading of liquid cargoes.

Estimates of the frequency and the amount of oil spilled because of possible pipeline accidents may be derived from statistics collected by the Office of Pipeline Safety Operations (OPSO), Department of Transportation.[8] By law, U.S. pipeline operators must report a spill from pipelines transporting a liquid product to the OPSO if the spill exceeds 50 barrels, or if there is an injury or death associated with the accident. The population of pipelines to which the spill statistics apply were obtained from the Bureau of Mines, Department of Interior. Every three years they report the total mileage of crude oil and oil product trunklines and gathering pipelines in the U.S. As of January 1, 1974, there were 222,355 miles of pipeline in the U.S., which are distributed fairly evenly between the three groups.[9] Of this total, 190,331 miles were 12 inches in diameter or less. Only 32,024 miles of pipeline were larger than 12 inches, and only 2,272 miles were 36 inches in diameter or larger.

The information on spills from pipelines is reported to OPSO on DOT Form 7000-1, and includes the owner of the pipeline, the spill location, the cause of the spill, the installation date of the pipeline, the diameter, the product carried, and the amount of oil spilled (usually a best estimate). Table 3.8 lists pipeline spills during the five-year period, 1971 through 1975, by cause. The major cause of spills from older pipelines, those installed before

Table 3-8

CAUSES OF PIPELINE LEAKS AND SPILLS
GREATER THAN 50 BARRELS
IN THE U.S. DURING 1971-1975

Cause	Pipelines 12 Inches and Less in Diameter		Pipelines Greater Than 12 Inches in Diameter
	Installed Before 1950 (Number of Incidents)	Installed After 1950 (Number of Incidents)	(Number of Incidents)
External Corrosion	297	50	9
Internal Corrosion	40	46	8
Line Ruptured by Excavation Equipment	142	128	28
Prior Damage by Excavation Equipment	6	18	3
Defective Pipe Seam	83	71	19
Defective Weld	22	11	7
Rupture of Gasket, Seal, etc.	23	56	2
Fire or Explosion	6	14	0
Flow Control Malfunction	3	11	0
Flow Control-Operator Error	23	12	0
Incorrect Operation by Carrier Personnel	2	11	0
Natural Disasters (Landslide, Flood, Windstorm, Freezing, etc.)	36	24	8
Unknown	55	67	8
TOTAL INCIDENTS	738	519	85

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1950, is external corrosion. Since the 1940's, much improved techniques have come into usage to prevent corrosion. Thus the major cause of spills in newer pipelines is accidental breakage by excavation or construction equipment. Most larger pipe, that greater than 12 inches in diameter has been installed since 1950, and for it, too, the major cause of spills is damage by excavation equipment.

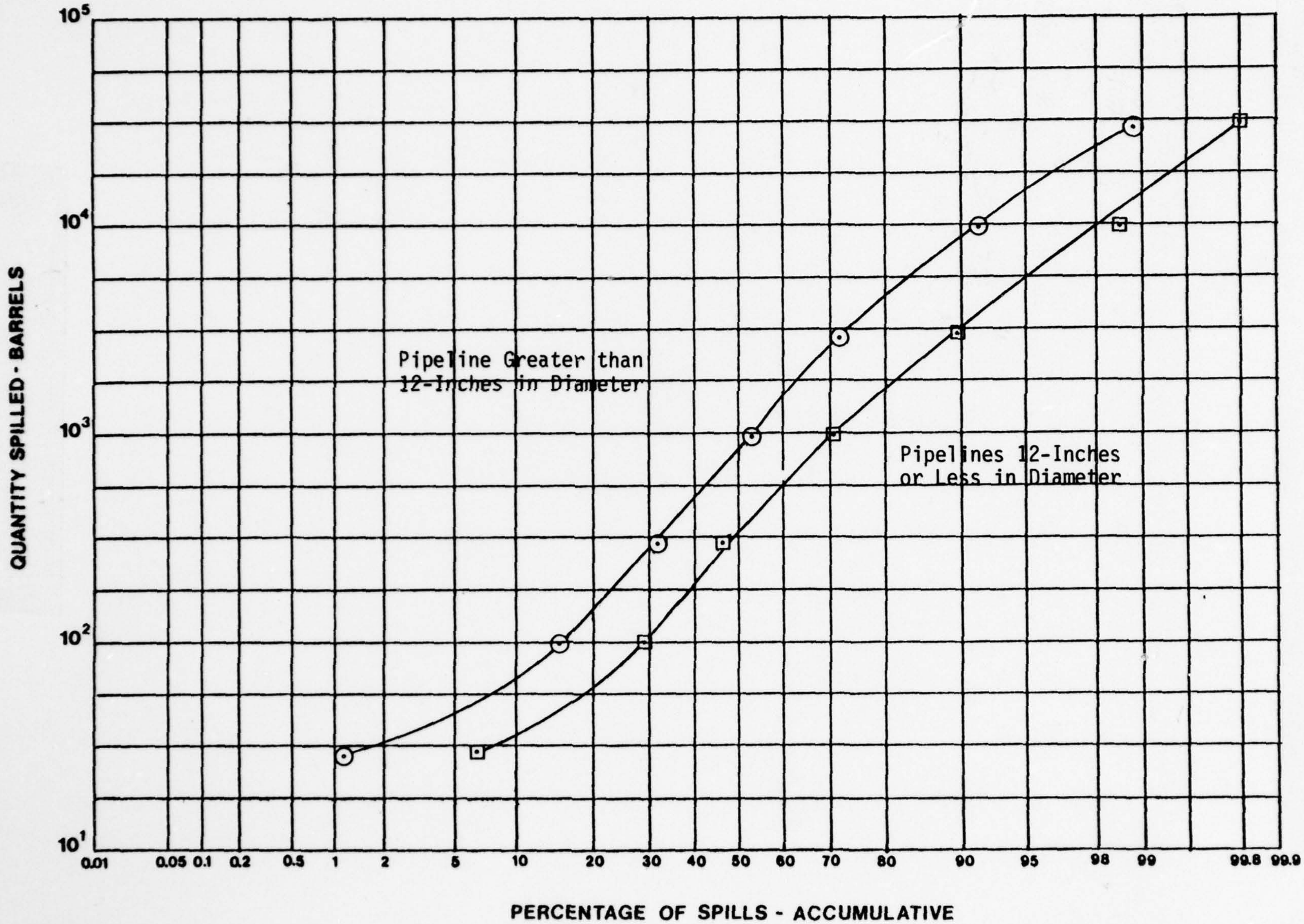
The spillage data were broken down into two categories according to size. There are insufficient data, statistically, for a breakdown for each individual size of pipeline. The spill rate (spills exceeding 50 barrels) from pipelines less than 12 inches in diameter was estimated by dividing the total number of spills by the mileage existing at the beginning of 1974, and normalizing to one year:

$$\frac{738 + 519}{190{,}331} \times \frac{1}{5} = 1.21\text{x}10^{-3} \text{ spills/mile-year (spills} > 50 \text{ bbls).}$$

The distribution of the sizes of the reported spills are plotted on log normal probability coordinates in Figure 3.3. For the larger diameter pipelines, these data show the median spill size to be approximately 850 barrels. For pipelines less than 12 inches in diameter, the median spill size is 360 barrels. For the larger diameter pipelines 8 percent of the reported spills exceeded 10,000 bbls. By cause, one-third of these larger spills resulted from corrosion and two-thirds from a defective pipe seam.

The spill data for underwater pipelines transporting liquids (mainly crude oil) is not as extensive as for terrestrial pipelines. During the period 1967 through 1976 there were a total of 17 spills of crude oil, exceeding 50 bbls., from leaks and breaks in underwater pipelines in the Gulf of Mexico Outer Continental Shelf. The spills are listed in Table 3.9. Seven of these

Figure 3-3. Size Distribution of Spills from U.S. Terrestrial Pipelines Transporting Liquids



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95%

Table 3-9

PIPELINE ACCIDENTS CONNECTED WITH FEDERAL OIL AND GAS OPERATIONS IN THE OUTER CONTINENTAL SHELF GULF OF MEXICO DURING 1967-1976

Source: USGS, Department of Interior

Area and Block Lease & Well No. Operator	Date and Duration	Type Accident, Related Depth	Controlled	Volume Oil Spilled (bbls)	Injuries, Fatalities, Damage to Property or Environment
1. Main Pass Blk 42 OCS-G 1367.	2-7-67	Pipeline leak. Cause unknown.	Line shut-in and repaired.	65	No recorded environmental damage.
2. West Delta Blk 73 OCS-G-1083.	10-15-67 to 10-27-67	Pipeline leak caused by anchor dragging.	Line shut-in and repaired.	160,639	No recorded environmental damage.
3. So. Timbalier Blk 131 OCS 0457	3-12-68	Pipeline break caused by anchor dragging.	Line shut-in and repaired.	6,000	No recorded environmental damage.
4. So. Timbalier Blk 44 Pipeline from S.T. 131, 135 & 176 flds. to B.M. Sta.	1-24-69 to 1-30-69	Pipeline leak probably caused by pigging.	Line repaired.	Est. over 100	No recorded environmental damage.
5. Ship Shoal Blk 214 OCS 0828, Production Facilities.	2-10-69	Pipeline leak.	Well shut-in. Pipeline repaired.	342	No recorded environmental damage.

Table 3-9 (continued)

Area and Block Lease & Well No. Operator	Date and Duration	Type Accident, Related Depth	Controlled	Volume Oil Spilled (bbls)	Injuries, Fatalities, Damage to Property or Environment
6. Main Pass Area Blk 299 OCS 1316.	2-11-69 to 2-16-69	Pipeline leak. Cause unknown.	Line shut-in and repaired.	7,532	No recorded environmental damage.
7. Ship Shoal Blk 216 OCS-G 1524, Well No. 4.	8-10-69	Flowline broken (unknown cause)	Safety valve shut-in well.	50	No recorded environmental damage.
8. South Pass Blk 27 OCS 0694, Platform "V".	5-31-70	Pipeline leak.	Pipeline shut-in	50	No recorded environmental damage.
9. West Delta Blk 29 OCS 0385.	11-14-71	Pipeline parted. (cause unknown)	Wells shut-in (spill boom deployed).	70	No recorded environmental damage.
10. Eugene Island Blk 238 OCS-G 0982, Platform "C".	12-17-71	Pipeline rupture caused by anchor dragging.	Safety system shut all wells except C-8 which was manually shut.	80	No recorded environmental damage.

Table 3-9 (continued)

Area and Block Lease & Well No. Operator	Date and Duration	Type Accident, Related Depth	Controlled	Volume Oil Spilled (bbls)	Injuries, Fatalities, Damage to Property or Environment
11. West Delta Blk 79 OCS-G 1449, Gas Gathering line connecting platforms "A", "B", "C", & "D".	6-26-72	Leak in 12" gathering line developed.	Repaired leak in line.	100	No recorded environmental damage.
12. West Delta Blk 73 16" pipeline to Grand Isle Blk 16.	5-12-73	Several small leaks discovered, caused by internal corrosion.	Line repaired, steps being taken to protect pipeline against further deterioration.	Over 5,000	No recorded environmental damage.
13. Eugene Island Block 317 Bonita Pipeline.	4-17-74	Break in pipeline most probably caused by an anchor dragging across it.	Pipeline shut-in and repaired.	19,833	No recorded environmental damage.

Table 3-9 (continued)

Area and Block Lease & Well No. Operator	Date and Duration	Type Accident, Related Depth	Controlled	Volume oil Spilled (bbls)	Injuries, Fatalities Damage to Property or Environment
14. Eugene Island Block 331, OCS-G 2116 Platform "A" 12" oil pipeline.	5-21-74	Storm caused derrick barge to drift, allowing it to drag its anchor across the pipeline, breaking the riser loose from the platform.	Pipeline shut-in and repaired.	100	No recorded environmental damage.
15. Main Pass Blk 73, Cobia Pipeline.	9-9-74	Pipeline broken by hurricane. Oil was pumped into the line before break was discovered.	Pipeline shut-in.	2,213	Beaches and shallow water in the Chandeleur Island area were cleaned up.
16. South Timbalier Block 130 OCS 0456 18" gathering line from "D" Platform to Bay Marchand shore facility.	2-29-76	Several leaks were discovered in the line.	Line was repaired and is in temporary use pending installation of new line.	414	No recorded environmental damage.

Table 3-9 (continued)

Area and Block Lease & Well No. Operator	Date and Duration	Type Accident, Related Depth	Controlled	Volume Oil Spilled (bbls)	Injuries, Fatalities Damage to Property or Environment
17. Eugene Island Block 297 Tie-in of Placid's 10" pipeline with Pennzoil's Bonita Pipeline	12-18-76	Shrimp trawl pulled loose a 1" ball valve.	Valve was repaired.	4,000	No recorded environmental damage.

spills exceed 1000 bbls: four caused by a dragging anchor or trawling, two caused by corrosion, and one apparently caused by a hurricane.

According to the Geological Survey they have permitted and approved a total of 8,077 miles of gas and oil pipeline in the Gulf of Mexico Outer Continental Shelf since August 1969.[10] Presently, they estimate that there is approximately 1000 to 1500 miles of pipeline installed prior to that date. Assuming that 50 percent of the pipelines is for crude oil, it is estimated that there are approximately 5000 miles of underwater pipeline transporting petroleum products. During the ten-year period, it is estimated that the average amount of underwater pipe transporting oil was 2500 miles. Therefore, the spillage frequency is estimated to be

$$\frac{17}{10} \times \frac{1}{2,500} = 6.8\text{x}10^{-4} \text{ spills/mile-year,}$$

a value which is of the same order-of-magnitude as for large diameter terrestrial pipelines.

During this same period there also were a larger number of small spills: a total of 236, 1 to 50 barrel spills of oil from pipelines, including pumps and all pipeline and auxillary equipment downstream of the pump discharge.[11] Of these, 58 percent were spills from the pipeline itself and most of these spills, 85 percent, were only small leaks. Spills of 1 to 50 barrels from non-pipeline systems on production platforms numbered 574 during the same period.[11] Of these 159 were from the sump system and 113 from the separator system. Both of these systems are similar in some respect to the oily water sump and separator, and the air eliminator systems that would be a part of the pumping platform of a deepwater port. Most of the spills from the sump were caused by poor design, the failure of the sump pump and the level control switch. Principal failures of the separator system included the failure of the high-low level control, the dump value (releases accumulated liquid), high-low pressure sensor, and leakage from the separator vessel and lines.

The U.S. Geological Survey also has collected data on other types of accidents involving drilling and production platforms in the Gulf of Mexico Outer Continental Shelf.[12] Table 3-10 lists accidents caused by damage to the platform structure itself. During the 12-year period covered, there were three platforms destroyed by a single hurricane, four platforms struck by ships or barges and a structural failure of the supports for an oil storage tank. Of the four ship or barge collisions, two resulted in spillage from the platform. These and other data used to estimate the frequency of different types of accidents to the platform are presented in Appendix C.

Table 3-10

SIGNIFICANT POLLUTION INCIDENTS*
RESULTING FROM ACCIDENTS DAMAGING
THE PLATFORM STRUCTURE IN THE GULF
OF MEXICO OUTER CONTINENTAL SHELF
1964-1976

Source: U.S.G.S., Department of Interior

Location	Date and Duration of Spill	Type of Accident	How Controlled [1]	Volume of Oil Spilled (bbls)	Damage
1. Eugene Island Blk 108 OCS 0576 Platform "A"	4-8-64 to 4-9-64	Struck by freighter; fire.	Fire control equipment.	2,559	Platform and freighter damaged. No recorded environmental damage.
2. Ship Shoal Block 149 OCS 0434, Platform "B"	10-3-64 (1 day)	Storage oil loss during hurricane.	Ceased	5,100	Platform destroyed. No recorded environmental damage.
3. Ship Shoal Block 198 OCS 0594, Platform "A"	10-3-64 (1 day)	Storage oil loss during hurricane.	Ceased	1,589	Platform destroyed. No recorded environmental damage.
4. Eugene Island Blk 208 OCS 0576, Platform "C"	10-3-64	Storage oil loss during hurricane.	Ceased	5,180	Lost platform. No recorded environmental damage.

*Spills of 50 bbls (2,100 gal) or greater.

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Table 3-10 (continued)

Location	Date and Duration of Spill	Type of Accident	How Controlled	Volume of Oil Spilled (bbls)	Damage
5. Ship Shoal Blk. 214 OCS 0828, Well No. 2	10-30-67-- Collision 9-8-68 to 9-29-68 Blowout	Blowout, gas & condensate. Freighter collided w/well. (Blowout occurred 1 yr. after collision.)	Cut casing and cemented	Minimal	Lost well and caisson protection.
6. West Delta Block 79 OCS-G 1449 Platform "A"	1-9-73	Structure supporting oil storage tank bent rupturing tank.	Modified and repaired tank and structure.	9,935	No recorded environmental damage.
7. Eugene Island Block 331, OCS-G 2116 Platform "A" 12" oil pipeline	5-21-74	Storm caused derrick barge to drift, allowing it to drag its anchor across the pipeline, breaking the riser loose from the platform	Pipeline shut-in and repaired	100	No recorded environmental damage.

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Table 3-10 (continued)

Location	Date and Duration of Spill	Type of Accident	How Controlled	Volume of Oil Spilled (bbls)	Damage
8. West Cameron Block 534 OCS-G 2226 Platform "A"	8-15-75	The tanker GLOBTIK SUN collided with the platform. Oil from the tanker ignited and the tanker caught fire.	Extensive fire-fighting operation.	None from platform.	Six tanker crewmen died. Platform damaged.

3.3 DWP OIL TRANSFER SYSTEM FAILURE MODES AND SPILL PROBABILITIES

The DWP Oil Transfer System was analyzed to determine the means by which oil spills might occur and with what probability. This analysis consists of several steps, namely:

1. system definition
2. failure mode identification
3. fault tree construction
4. failure rate data collection
5. fault tree evaluation

These steps are completed in basically the order shown, however, several iterations are required through Steps 1-4 to ensure that the faults which have been selected accurately represent the system being analyzed and the available data. For discussion purposes, the description of the DWP system, its components, and the operating procedures given in Section 2.4 is adequate, however, a much more comprehensive understanding of components was necessary to identify potential causes of oil spills. Therefore, a Failure Modes and Effects Analysis (FMEA) was completed for all DWP components. Due to the long list of system components, the FMEA results are presented in Appendix B. Component failure modes which could result in a violation of the oil transfer system integrity were of principal interest in the FMEA, since those were to be included in the fault trees.

The results of the FMEA indicate that, throughout the oil transfer system (OTS), component rupture or deterioriation was a major source of oil spill potential. In some cases a backup system exists to prevent oil spilled from the OTS from reaching the sea, e.g., the waste disposal system on the pumping platform. For other parts of the OTS, the most important, if not the only, spill mitigation provision is human supervision. There are many possible scenarios of human errors which could result in an oil spill, either onto the platform or directly onto the sea. A partial list of these is shown in Table 3-11. The details of the control system which is the subject of a separate study, may affect some of these error rates.

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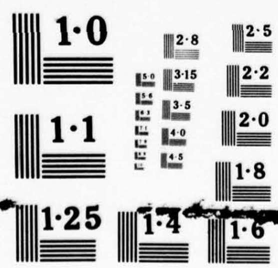

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MICROCOPY RESOLUTION TEST CHART

Table 3-11

HUMAN ERROR SCENARIOS

I. SHIPBOARD ERRORS*

A. Improper hose connection and error missed by Cargo Manager and leak not evident during startup.

B. Ship's scuppers not plugged and error missed on checklist.

C. Leak between ship and buoy not observed.

D. Oil left in hose following offloading and hose damaged (dropped or anti-chafe blanket not used).

E. Signal to stop offloading received and signal ignored.

F. Mooring launch run across hose and damages it.

G. Alignment of shipboard valves

II. PLATFORM ERRORS

A. Drain line left open at sampler, strainer, air eliminator, pump, meter, launcher, or prover and supervisor fails to detect the error.

B. Valves arranged improperly.

C. Leak from pipeline or equipment not observed.

D. Maintenance error - procedures not followed carefully, maintenance not completed at the correct time, wrong parts used.

III. MAIN CONTROL ERRORS

A. Improper valve arrangement and not detected.

B. Instrument warning or alarm ignored.

C. Change in flow rate not detected.

---

*Shipboard operations not directly related with oil transfer from ship's tanks to the DWP are not included, e.g., ballasting operations or discharging bilge. These, too, could conceivably result in a spill onto water.

It is apparent that a succession of failures must occur for a spill to result which means that a cautious and vigilant staff can greatly reduce the oil spill probability.

The next step in the safety analysis of the OTS is the construction of fault trees. A fault tree is a logic diagram which describes the ways in which component failures and other events can result, either alone or in combination, in the top event of the tree. This top event is the undesired event for which the probability of occurrence is desired. In this case, the top event is "Oil Spilled from DWP." The basic events on the tree are combined through Boolean "AND" and "OR" gates and, when all the failure probabilities are supplied, the probability of the top event can be calculated.

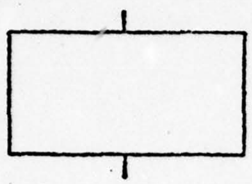
Fault tree analysis was first used by Bell Laboratories in 1960, and has been used extensively by the military and aerospace industries since that time in the prediction of missile and aircraft reliability. The methodology was recently used to predict the probability of accidents for nuclear power plants, and the results were reported in the Reactor Safety Study (Reference 13). The symbols used in fault tree analysis are shown and explained in Figure 3-4.

The failure probabilities which appear on the fault trees constructed during this project were drawn from the failure rate data base presented in Appendix C and are summarized in Table 3-12. The units for the failure probabilities in the table are per unit time or per demand. The annual spill frequency from the DWP is the quantity desired, so the failure probabilities must be modified to reflect a year's service. For events with a failure rate given per unit time, the annual failure frequency is the failure rate times the length of time the component is in service during a year. For example, the probability of hose string leak is 1×10^{-3}/hr, and the hose strings are in operation 12410 hours/yr, so the annual frequency of hose leaks is

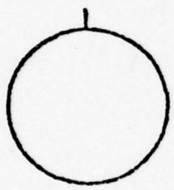
$$\frac{1 \times 10^{-3}}{\text{hr}} \times 12410 \frac{\text{hrs}}{\text{yr}} = 12.4 \frac{\text{leaks}}{\text{yr}}$$

EVENT REPRESENTATIONS

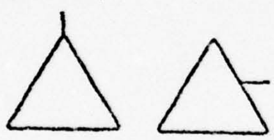
The rectangle identifies an event that results from the combination of fault events through the input logic gate.



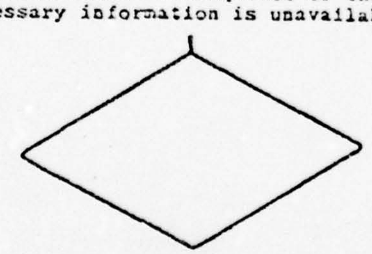
The circle describes a basic fault event that requires no further development. Frequency and mode of failure of items so identified are derived from empirical data.



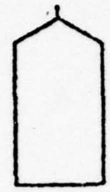
The triangles are used as transfer symbols. A line from the apex of the triangle indicates a transfer in and a line from the side denotes a transfer out.



The diamond describes a fault event that is considered basic in a given fault tree. The possible causes of the event are not developed whether because the event is of insufficient consequence or the necessary information is unavailable.

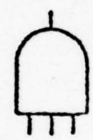


The house is used as a switch to include or eliminate parts of the fault tree as those parts may or may not apply to certain situations.



LOGIC OPERATIONS

AND gate describes the logical operation whereby the coexistance of all input events is required to produce the output event.



OR gate defines the situation whereby the output event will exist if one or more of the input events exists.

INHIBIT gates describe a causal relationship between one fault and another. The input event directly produces the output event if the indicated condition is satisfied. The conditional input defines a state of the system that permits the fault sequence to occur, and may be either normal to the system or result from failures.

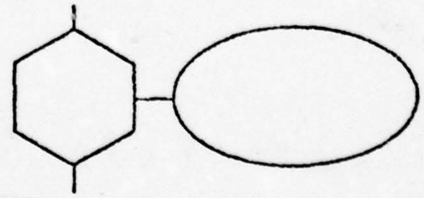


Figure 3-4. Fault Tree Symbolism

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Table 3-12

FAILURE RATE DATA

Component Failure/Event/Activity	Failure Rate	Data Source[1/]
Pump - fails to start	$1x10^{-3}$/D	RSS
Level Switch - fails to operate	$3x10^{-4}$/D	RSS
Flange - leak	$3x10^{-7}$/hr	RSS
Gasket - leak	$3x10^{-6}$/hr	RSS
Weld - leak	$3x10^{-9}$/hr	RSS
Valves - MOV or Check - external leak or rupture	$1x10^{-8}$/hr	RSS
Pipe - leaks, all causes	$1x10^{-7}$/ft-yr $1x10^{-11}$/ft-hr	OPSO
Pipe - weld leaks	$3x10^{-8}$/ft-yr	OPSO
Pipe - corrosion failure	$2x10^{-8}$/ft-yr	OPSO
Hose - leak from string	$1x10^{-3}$/hr	OE
Hose - external damage	$2.2x10^{-6}$/hr	OE
Mooring - lines break	$4.9x10^{-5}$/hr	OE
Ship Expansion Joint - leaks	$4.9x10^{-5}$/hr	OE
Fluid Swivel - leaks	$4.9x10^{-5}$/hr	OE
Operator - verify switch position	$2x10^{-3}$/D	Sandia
Operator - verify component installed/removed	$1.2x10^{-3}$/D	Sandia
Operator - close-hand valve	$1.7x10^{-3}$/D	Sandia
Operator - complete procedure	$3x10^{-3}$/D	Sandia
Ship Collision - spill	$1.4x10^{-4}$/yr	USGS
Fire or Explosion - spill	$3x10^{-4}$/yr	USGS
Platform Supports - structural failure	$9x10^{-5}$/yr	USGS
Waste System - spill	$6.0x10^{-3}$/yr	USGS
Pump - mechanical seal leaks	$6x10^{-6}$ hr	2/
Underbuoy Hose - leaks	$1.2x10^{-4}$/hr	2/

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Table 3-12 (continued)

Component Failure/Event/Activity	Failure Rate	Data Source[1/]
Vane Straightener - leaks	$3x10^{-9}$/hr	2/
Turbine Flow Meter - leaks	$3x10^{-9}$/hr	2/
Deck - hole not repaired	$1x10^{-5}$/hr	2/
Hose - Filled with oil between ships	0.6	2/
Earthquake	$<10^{-6}$	2/

1/ OE - Operating Experience values derived in Section 3.1.

RSS - Reactor Safety Study, Reference 13.
OPSO - Office of Pipeline Safety Operations, values derived in Section 3.1
Sandia - Reference 14.
USGS - U.S. Geological Survey, values derived in Appendix C.

2/ Calculated using the assumption stated in the text of Appendix C.

Other events have a failure probability per demand. That is, each time the action is required the probability of failure is that shown in the table. To calculate the annual failure frequency, the rate must be multiplied by the annual frequency with which the action will be needed. For example, the probability that an electronic float switch will fail to function is 3.0×10^{-4}/demand. The high level float switch on each air eliminator will be required to function at least twice during the off-loading of each ship, and there are 776 ships/year. Therefore, the annual failure probability for the float switches on the air eliminators is

$$\frac{3.0 \times 10^{-4}}{\text{demand}} \times \frac{2 \text{ demands}}{\text{ship}} \times \frac{776 \text{ ships}}{\text{year}} = .47/\text{year}$$

The event for which this analysis was done is "Oil Spilled from the DWP." This fault tree is shown in Figure 3-5. It indicates that a spill from the DWP can come from any of eight sources: ship, hose strings, SPMs, SPM pipelines, pumping platform, pipelines, or onshore facilities. Both CALM and SALM designs were analyzed so spill frequencies for each are given. The overall spill frequency per year is 16.5 assuming CALM SPMs are used and 14.9 assuming SALM buoys are used. (Estimates of spill sizes will be discussed in Section 3.4).

Causes of potential spills from the OTS components on a ship are presented in tree B1, Figure 3-6. According to OCIMF and Coast Guard regulations, a drip pan must be installed under the connection manifold onboard each oil tanker (See Section 2.3). Spills from butterfly valves on the hose, the isolation valves on the ship or gasket leaks will drain into the drip pan, so it must overflow or leak for a spill onto the deck to occur. (No credit is given for a drain line from the drip pan back to a cargo tank since this is usually a small line and is not always present.) The probability that the drip pan will overflow is estimated as the probability that the tank is not checked regularly and is full of water or oil, 3×10^{-3}/demand.

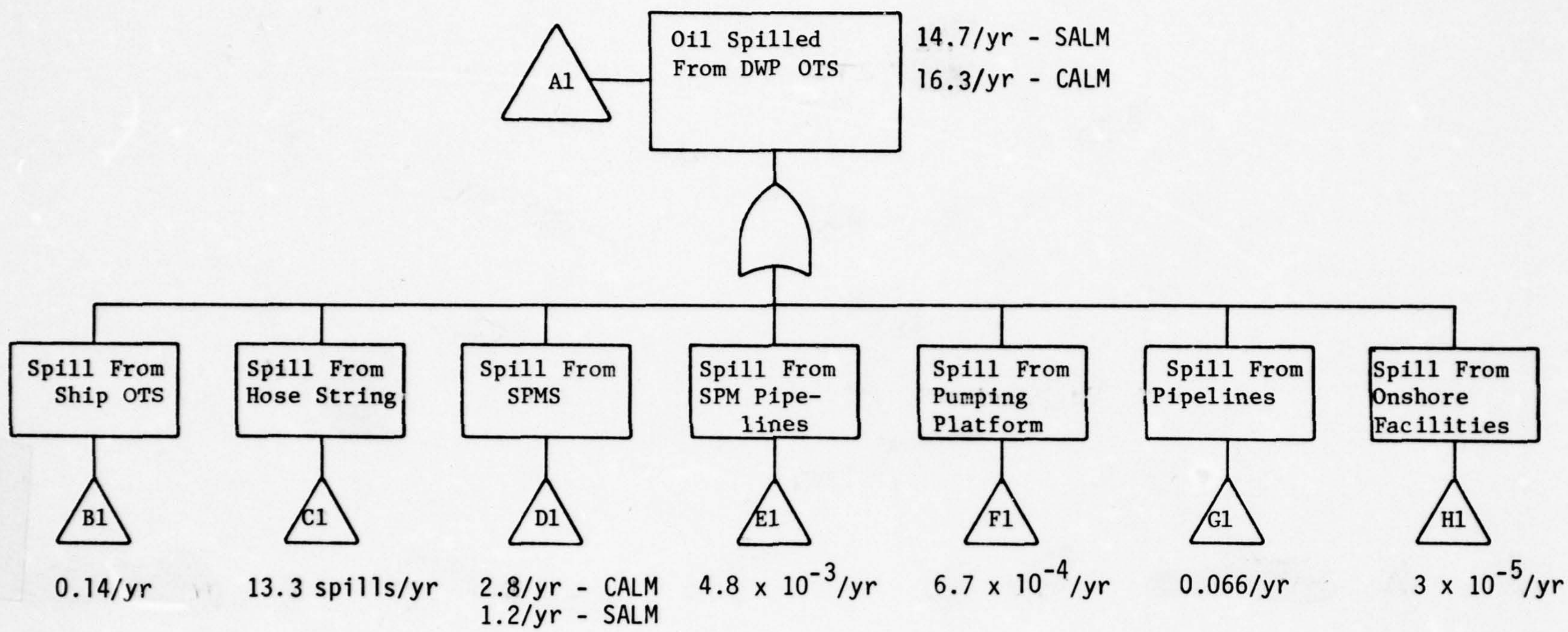

Figure 3-5. Fault Tree A1, "Oil Spilled from DWP"

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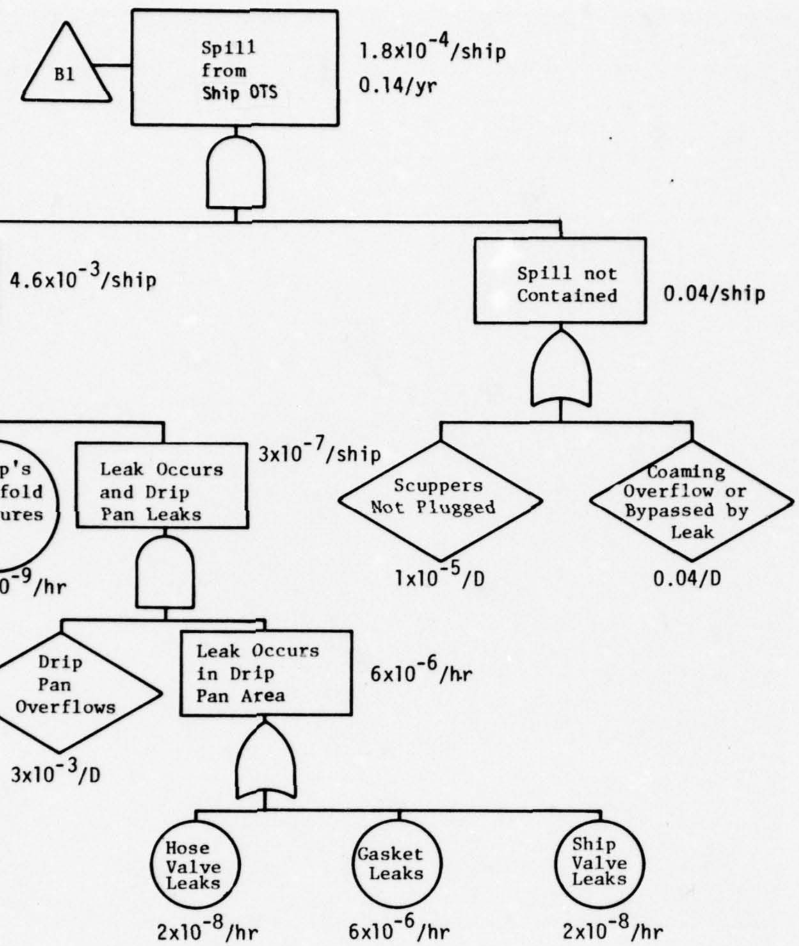

Figure 3-6. Fault Tree B1, "Spill from Ship"

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The expansion joints and additional manifold piping on the ship may not drain into the drip pan, so any leak from either spills onto the deck. The ship's scuppers are to be plugged prior to connection of the hoses, but potentially that task could be overlooked by both the crewman and supervisor. A total of 36 scuppers was assumed for each ship (50' apart, 800' ship = 32 scuppers). Additionally, the leak from a ruptured expansion joint valve could be very large and overflow the coaming or spurt over the vessel side. The probability of this occurrence, given a rupture, was assumed to be 0.04. This estimate is based on Figure 3-2, in which 4 percent of all operational spills during offloading and loading at a dock exceed 20 barrels in size. The maximum volume of oil spilled onto the deck and retained by the coaming with the scuppers plugged was estimated to be 20 barrels.

Spills from the hose strings are represented in tree C1, Figure 3-7. During offloading operations, hose leaks can occur from the gasket at the buoy swivel, from any of the hose sections, or from numerous places if breakout occurs. The individual hose sections could leak because of a nipple-hose bond failure, liner collapse, kink, gasket leak between sections, abrasion of the cover, or fracture of all hose layers. Sufficient data regarding the relative frequencies of each type of failure do not exist, so all failure modes are combined. Some visual inspection of the hoses could identify potential failures due to kinks or hose damage; however, others such as gasket leaks might be difficult to detect. Leaks due to pressure surges are included in the diamond "leak from hose section."

Spills can occur from hose strings while no ship is moored to the buoy if the hose is left full of oil after the previous transfer took place. Regulations require that the oil be drained from the hoses if the time interval between transfers is expected to be greater than seven days. Based on a throughput rate of 3.4×10^6 bbl/day, 1.6×10^6 bbl/ship, and 100,000 bbl/hr offloading rate, the hoses would be left full of oil between ships 100 percent of the time.

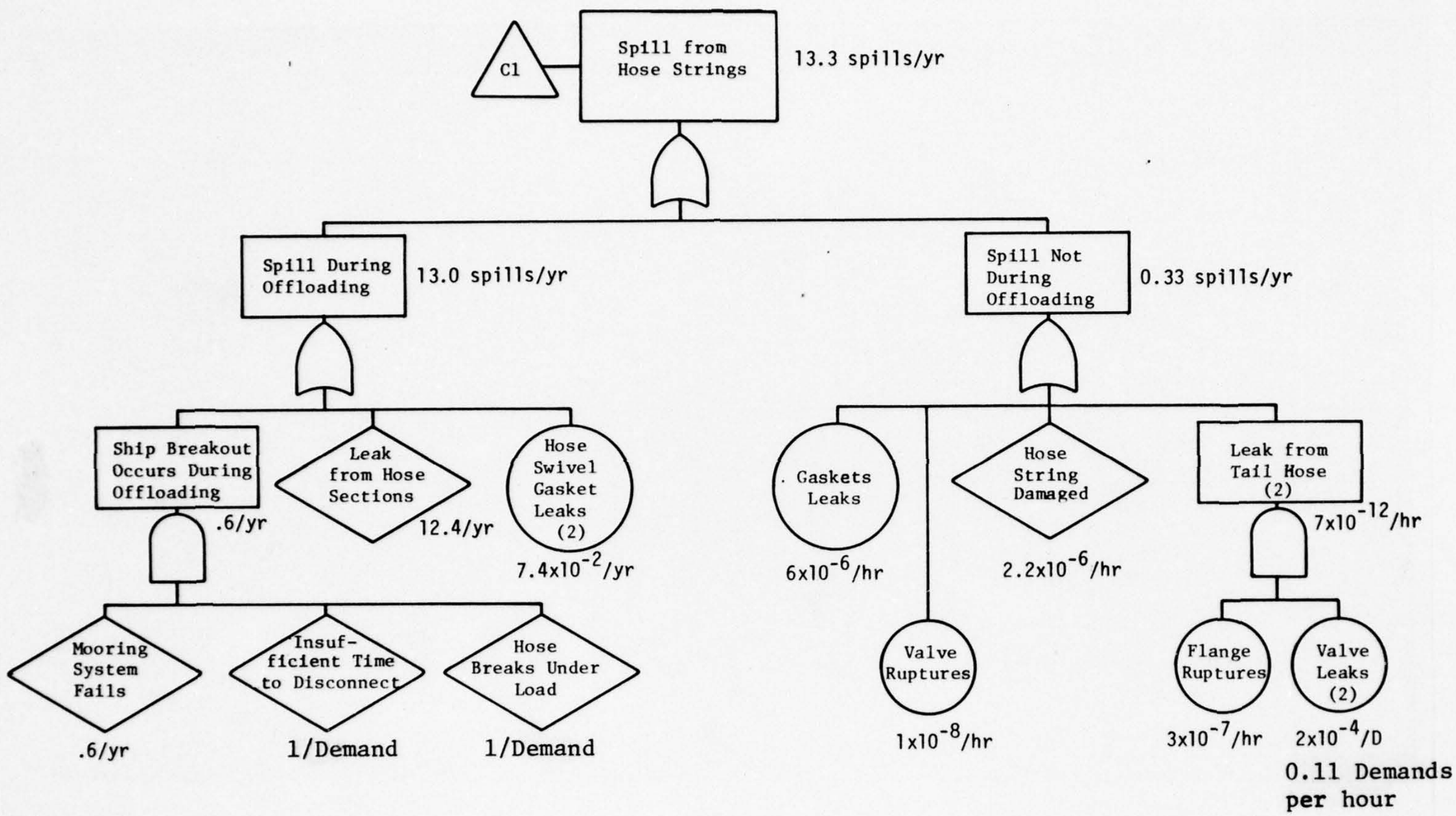

Figure 3-7. Fault Tree C1, "Spill from Hose Strings"

(498)

Leaks could come from the tail hose (both flange and butterfly valve must leak), from the hose-swivel gasket, or from a damaged hose section.

Spills caused from CALM SPMs are presented in tree D1, Figure 3-8. Spills could occur from any of the principal OTS components of a CALM SPM: the overboard piping, the valves, the product distribution unit, the underbuoy hoses, or the pipeline end manifold (PLEM). Failures caused by motion of the PLEM on the sea bed were included in pipe rupture probability for the SPM pipelines. The underbuoy hoses are assumed to be 1.5 times the water depth (100') in length, and, it is assumed that their failure probability is proportional to that of the floating hoses, even though the causes of failure may be different for the two hoses. For instance, failures due to chafing for the underbuoy hoses occur more often in the first-off-the-PLEM section. Floating hoses experience chafing-caused failure principally in the tail hose. Similar detection problems exist for gasket failures in underbuoy hoses and floating hoses since fabrication and installation techniques are similar.

Spill causes from SALM SPMs are presented in Figure 3-9 in a tree also labeled D1. The design represented here is for a shallow water (<150') installation so no riser pipe is included. Also, a solid pipe connection between the torus and PLEM is assumed whereas flexible hoses may be called for in some cases. The fluid swivel assembly is protected from leaks by multiple, redundant fluid seals. Double, and sometimes triple, oil seals are used to minimize the threat of leakage and to facilitate inspection. In this analysis, it is assumed that the water seal offers no protection against outward leakage of oil from a double oil seal assembly.

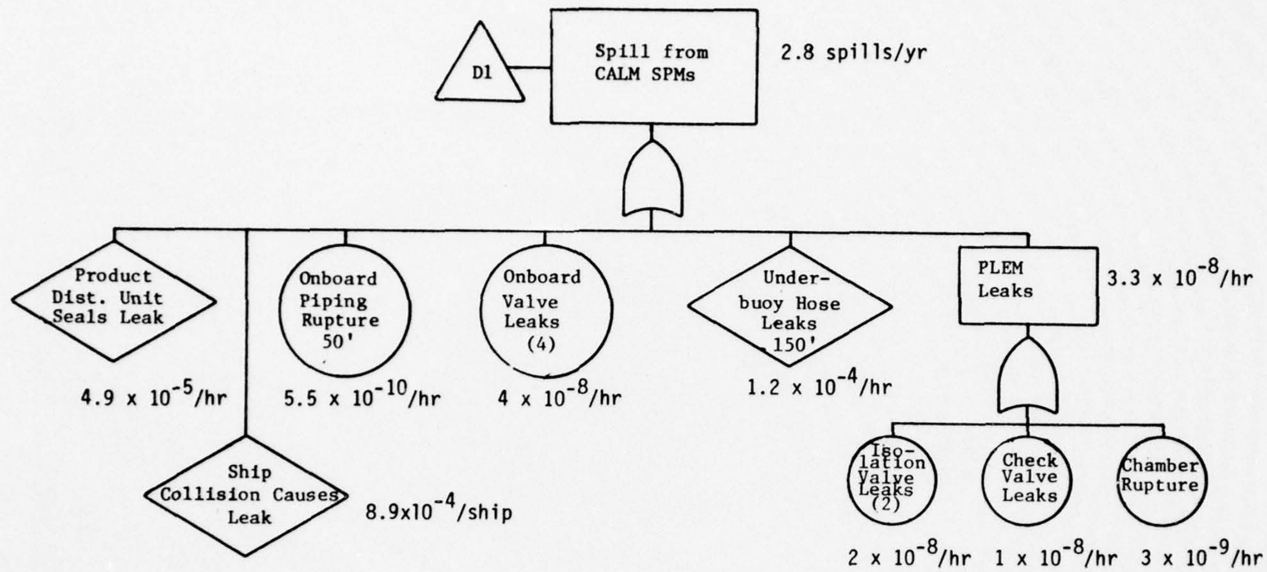

Figure 3-8. Fault Tree D1, "Spills from CALM SPMs"

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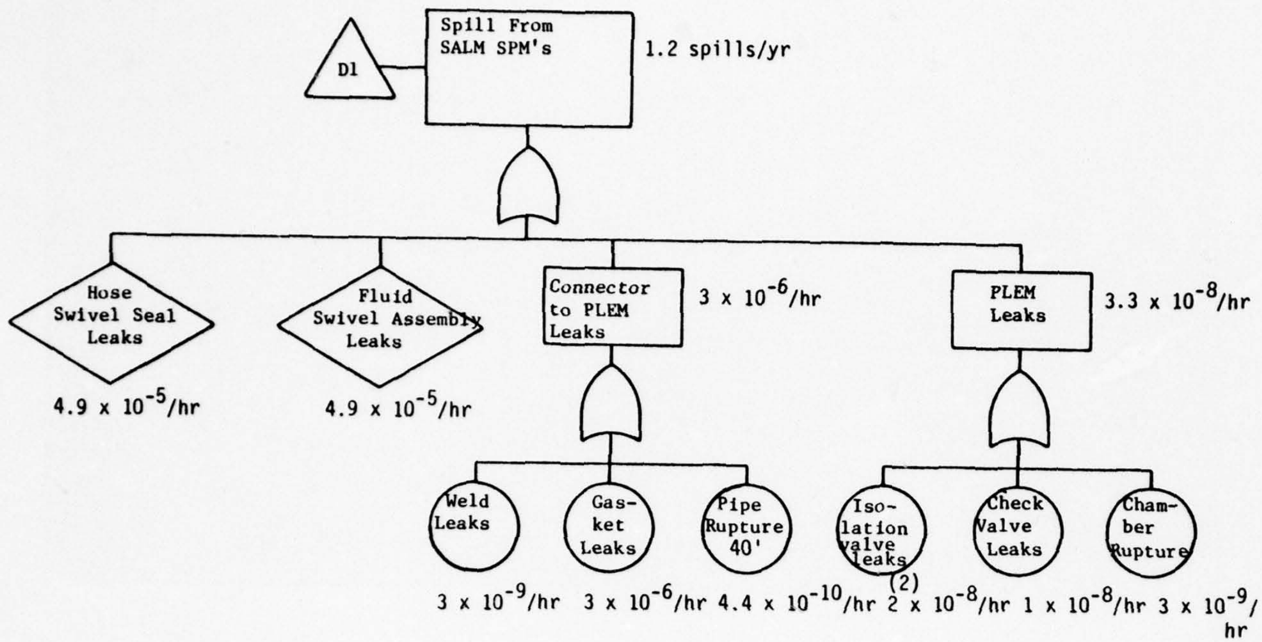

Figure 3-9. Fault Tree D1, "Spill from SALM SPM's"

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Tree E1 (Figure 3-10) contains the fault tree for spills from the six SPM pipelines. Pipe failures due to corrosion, weld defects, and other causes are included as well as failure of the check valve located at the pumping platform.

The potential causes of spills from the pumping platform are presented in trees F1-F5, Figures 3-11 to 3-15. A spill from the platform can be caused by an event which damages the structure itself, by a leak in the waste disposal system, or by the occurrence of a leak on the platform and a failure of the waste disposal system. Structural damage could be caused by failure of the platform supports due to corrosion or settling, by collision by a ship, by explosion or fire on the platform, or by earthquake. For an explosion to occur which could result in a spill there must be an accumulation of explosive materials and a failure of the sensing devices. These failures do not appear on the tree due to lack of sufficiently detailed data.

The OTS on the pumping platform was divided into three sections for analysis: the section upstream of the pumps is shown on tree F2, the pump section on tree F3, and the section downstream of the pumps on tree F4. Upstream of the pumps, the principal sources of leaks are the air eliminators, strainers, samplers, flanges, piping, and valves. These lines contain oil at all times except when they are out of service for maintenance or repair. Then, they are drained to the maintenance oil drain tank. OTS integrity is lost if the drain valve is not closed following maintenance. Semi-annual maintenance was assumed for both the air eliminator and sampler on each line. Monthly maintenance was assumed for each strainer. Oil could escape the air eliminator vent if the high level switch which closes the vent valve were to fail. It was estimated that the high level switch would be exercised at least twice for each ship offloaded, or 1552 times/year.

The pump section failures include failure of pump housing, seals, valves piping, and control valves. The seals serve as the boundary between the oil and the air in the region of the pump shaft. The seals must be lubricated at all times and maintained regularly. They are usually equipped

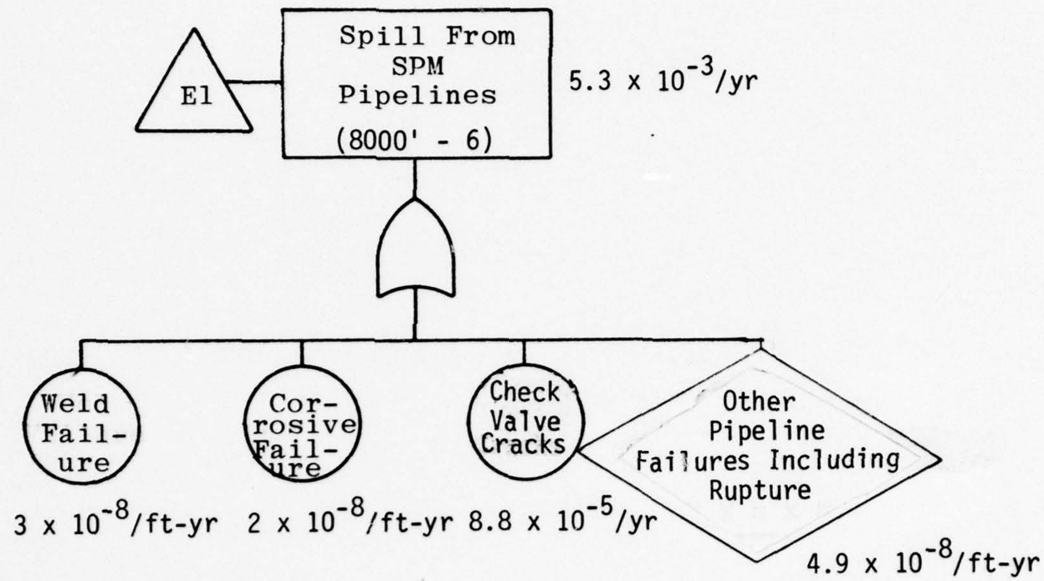

Figure 3-10. Fault Tree E1, "Spill from SPM Pipelines"

503

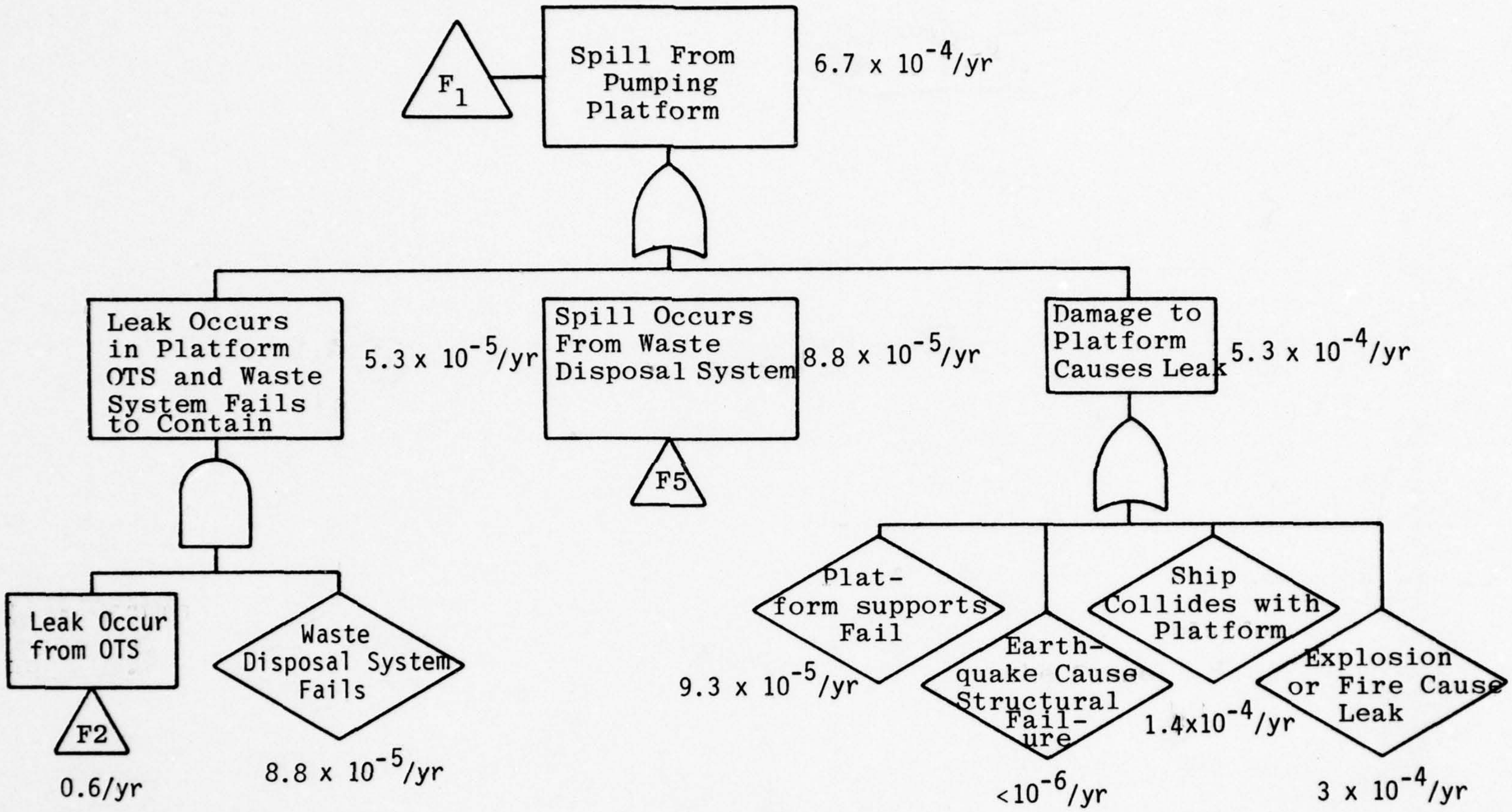

Figure 3-11. Fault Tree F1, "Spill from Pumping Platform"

504

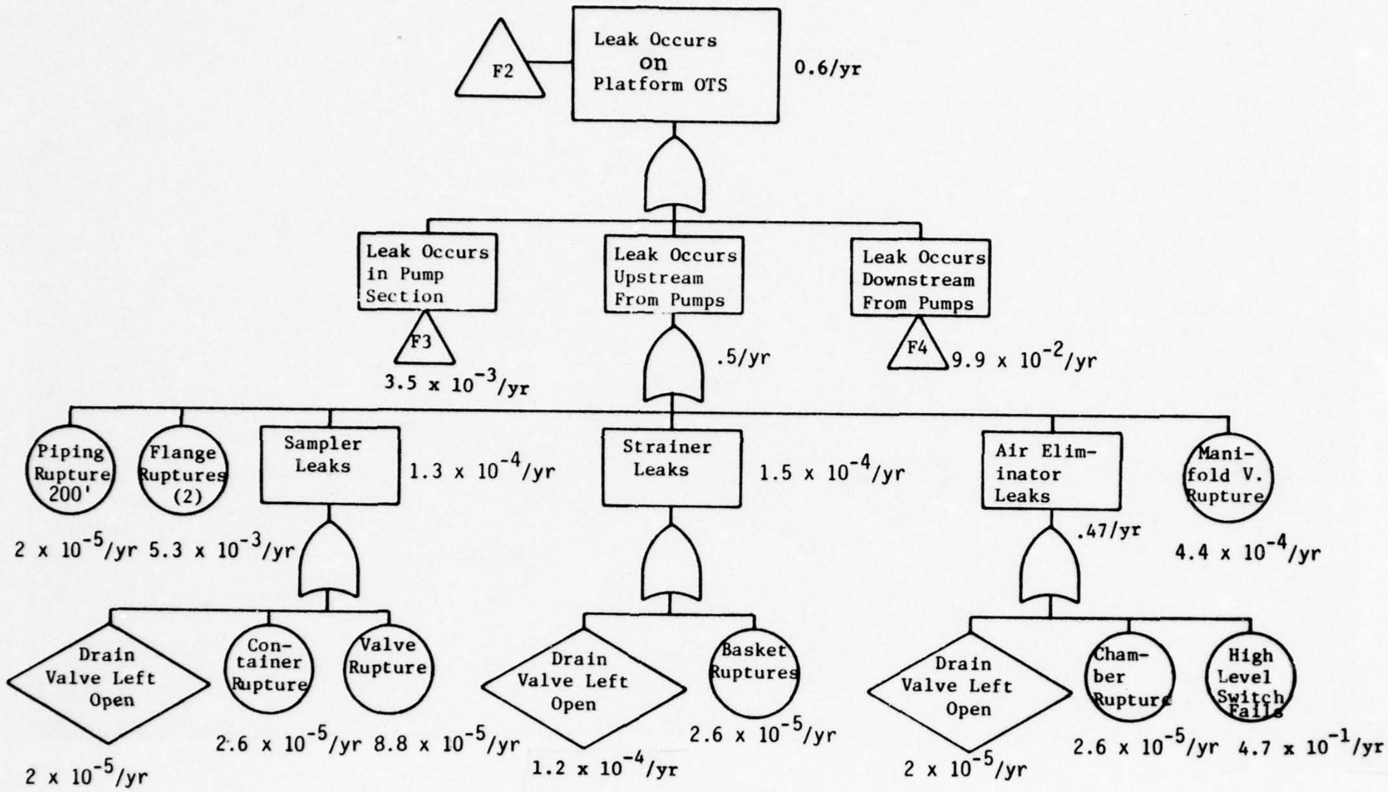

Figure 3-12. Fault Tree F2, "Leak Occurs on Platform OTS"

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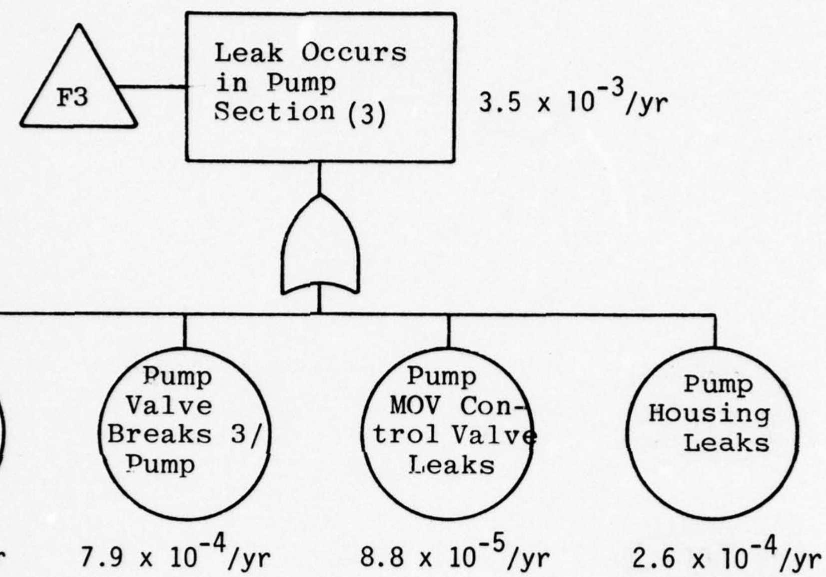

Figure 3-13. Fault Tree F3, "Leak Occurs in Pump Section"

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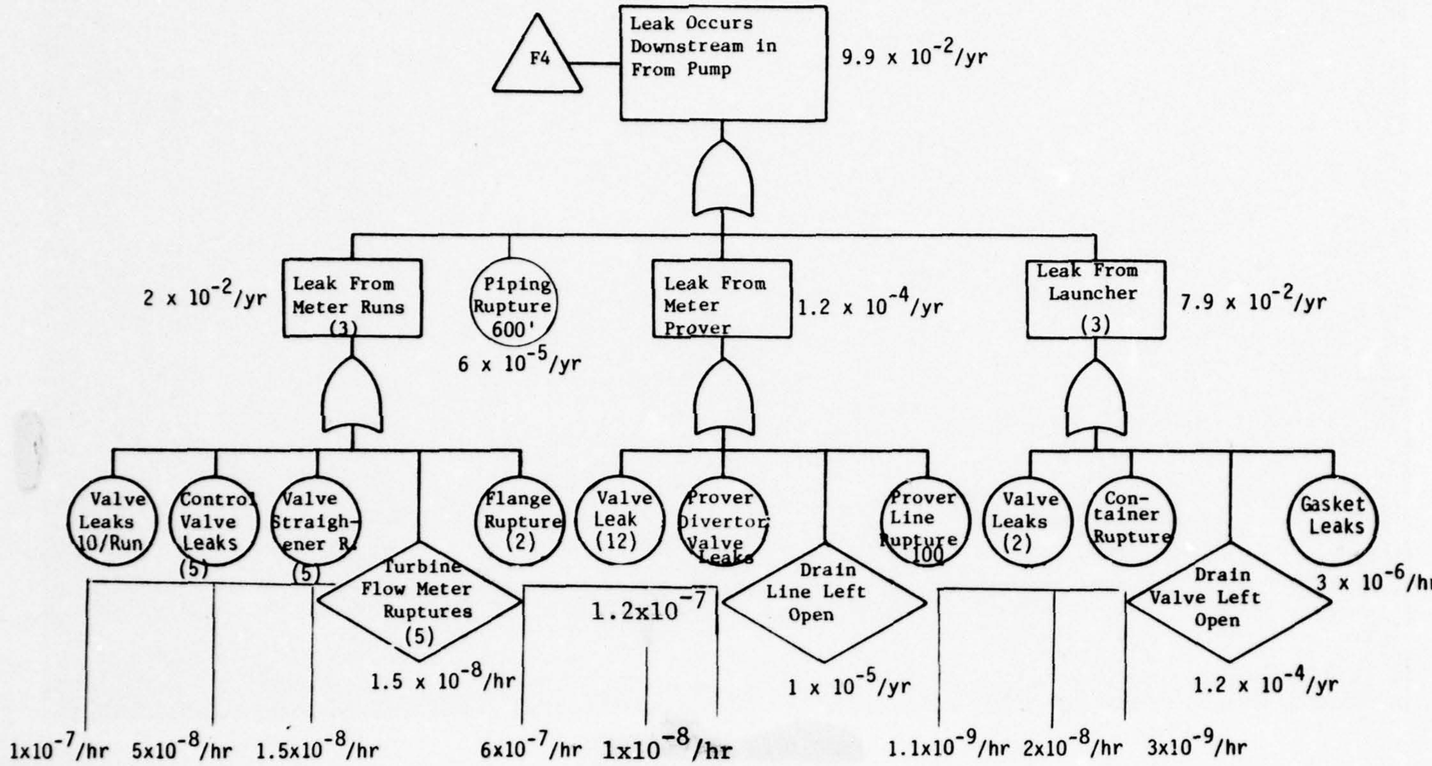

Figure 3-14. Fault Tree F4, "Leak Occurs Downstream from Pump"

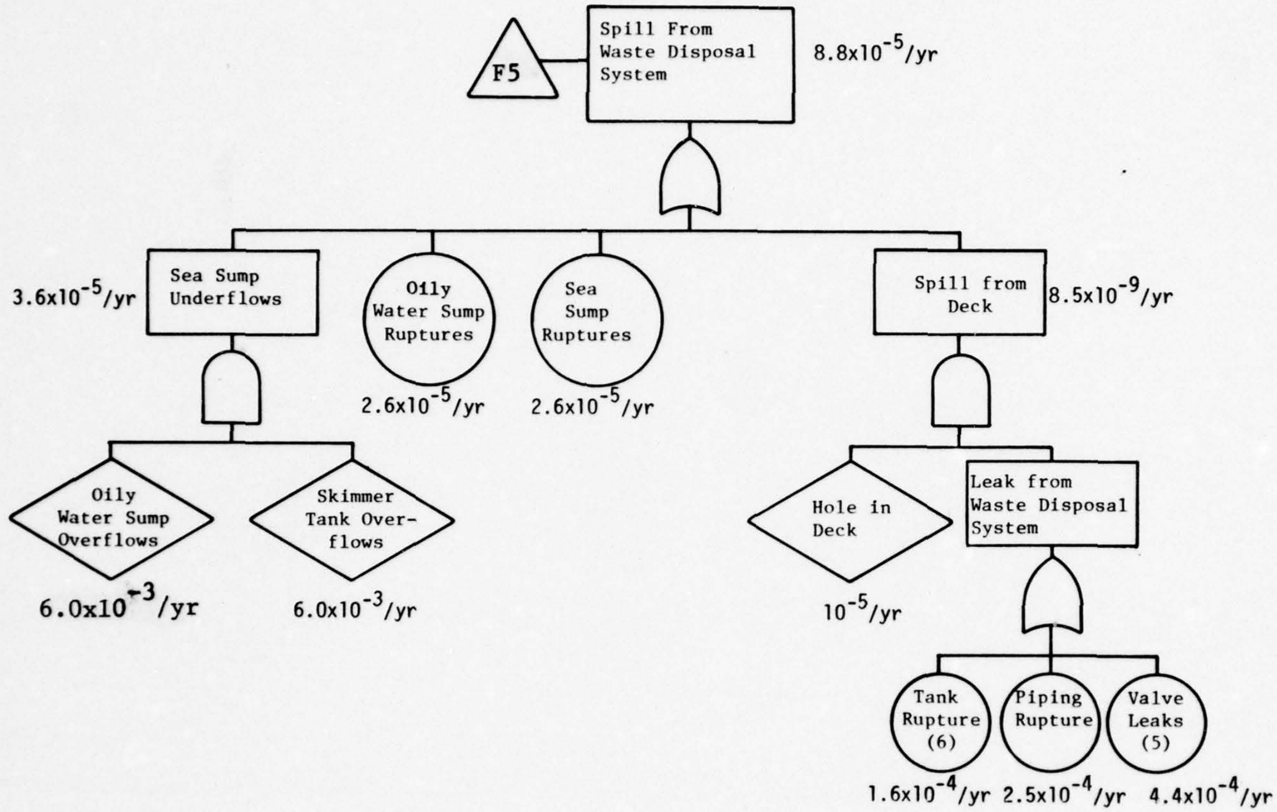

Figure 3-15. Fault Tree F5, "Spill from Waste Disposal System"

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with a sensing system to indicate high temperature. Should the seals fail, an automatic shutdown system turns off the pump. Leaks from a pump housing are assumed to be as frequent as similar leaks from large motor-operated valves, a conservative assumption.

Downstream of the pumps, the flow meter runs, the meter prover, and the launchers are potential sources of leaks. All of these lines are left full of oil between usage except when out of service for maintenance. It is assumed that the meter prover will be drained for maintenance once per year and each launcher will be used (and drained) on a monthly basis.

The waste disposal system failures which could result in a spill appear on tree F5. The waste disposal system is closed so that oily water is recycled until sufficient cleaning has been completed before the water is released to the sea and oil returned to the pipeline. If the transfer pump which recycles fluid from the sea sump fails to start, the sea sump could underflow to the sea. Also, under certain valve alignment, the maintenance oil tank pump could pump reclaimed oil out of air eliminator vent. Rupture of either the sea sump or the oily water sump would also result in a spill. It is assumed here that all pumps in the waste disposal system are operated once per day.

Failures of the offshore and onshore pipelines have been combined and are shown on tree G1, Figure 3-16. Weld failures and failure of the corrosion protection of the pipelines have been separated from all others. Rupture and damage due to external causes are both included in the "other" category.

The failures which could cause a spill from the onshore facilities are shown in Tree H1, Figure 3-17. These include failures at the booster pump station and at the storage facilities. Consideration of the storage facility includes all plumbing from the incoming pipelines to the root valve of each of the 20 storage tanks. Because of the drain system, berms, and collector pans at the booster pump station and the storage facility, an oil spill requires failure of both the OTS integrity and the containment dikes. A probability of 2×10^{-3}/D was assigned to the failure of a containment dike. This was based primarily on the likelihood that a dike drain valve is inadvertantly left open by facility personnel (Appendix C, Table C-6). For the storage facility there are two dikes and hence the probability of containment failure is 4×10^{-6}/D.

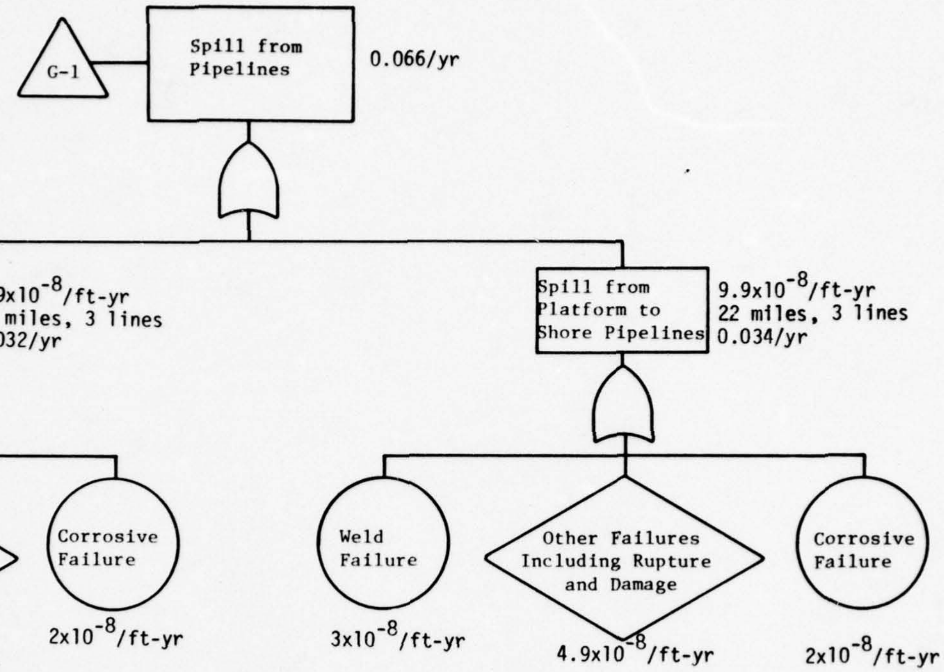

Figure 3-16. Fault Tree G1, "Spill from Pipelines"

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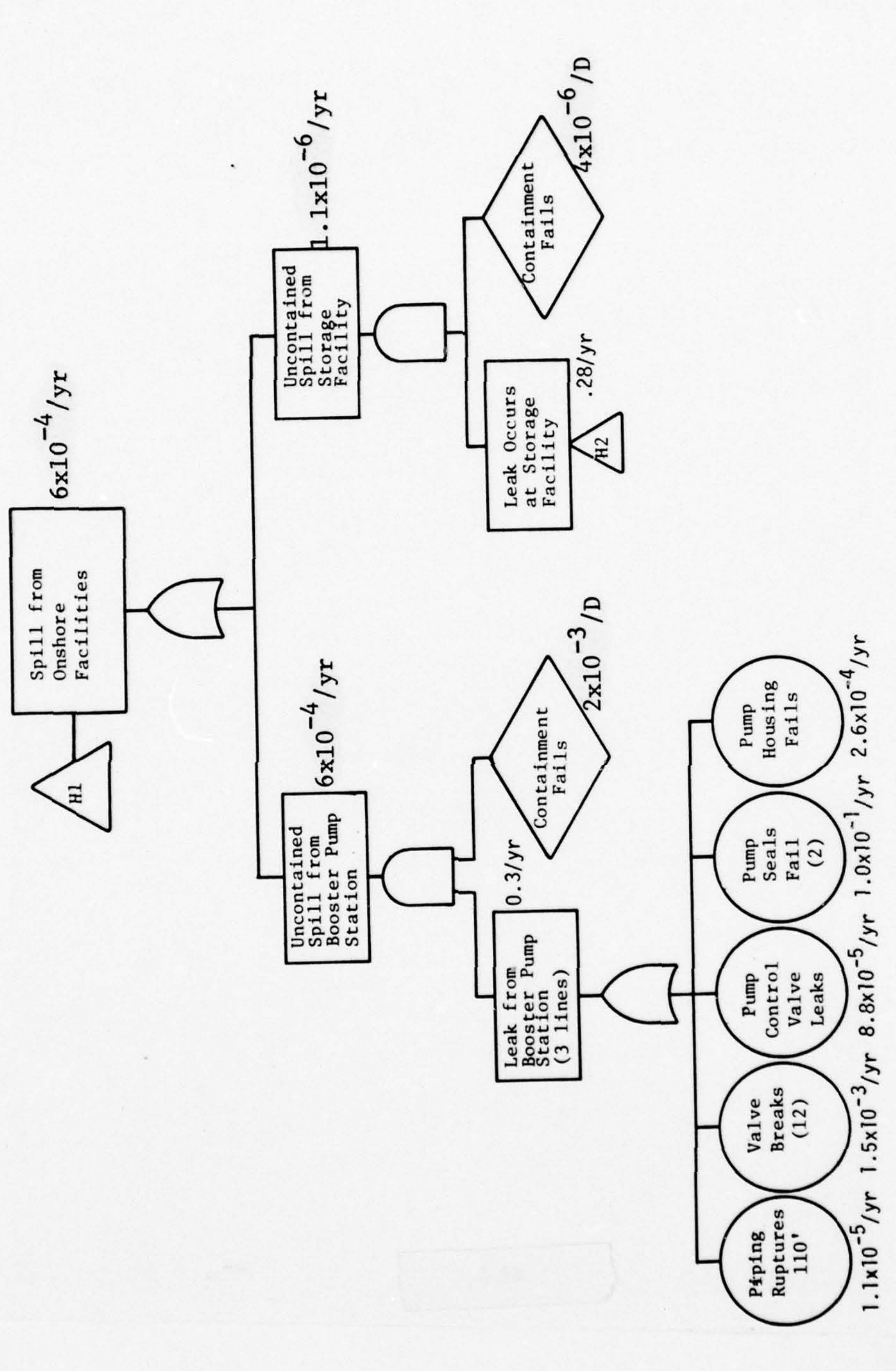

Figure 3-17. Fault Tree H1, "Spill from Onshore Facilities"

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The events which could cause oil to leak from the OTS are shown on Tree H2, Figure 3-18. These include leaks from: piping, scraper receivers, meter runs, meter prover, and waste disposal system.

To summarize the fault trees, the failures which can result in an oil spill have been grouped according to whether a single event, two successive or coincident events, or three events must occur to produce a spill. These results are presented in Table 3-13 below. Spills which result from single failures occur from the parts of the OTS which have no installed spill containment system. For those, any leak results in a spill of oil, although some spill volumes may be very small. Detection depends on observation and instrumented flow detection systems. Doubles have one line and tripes have two lines of defense between the leak source and the sea, in addition to the instruments and the personnel.

These results give an indication of the frequency of all spills from a DWP without regard for the size of the spill. The assessment of the risk from the spills also includes the spill size which is discussed in the next section.

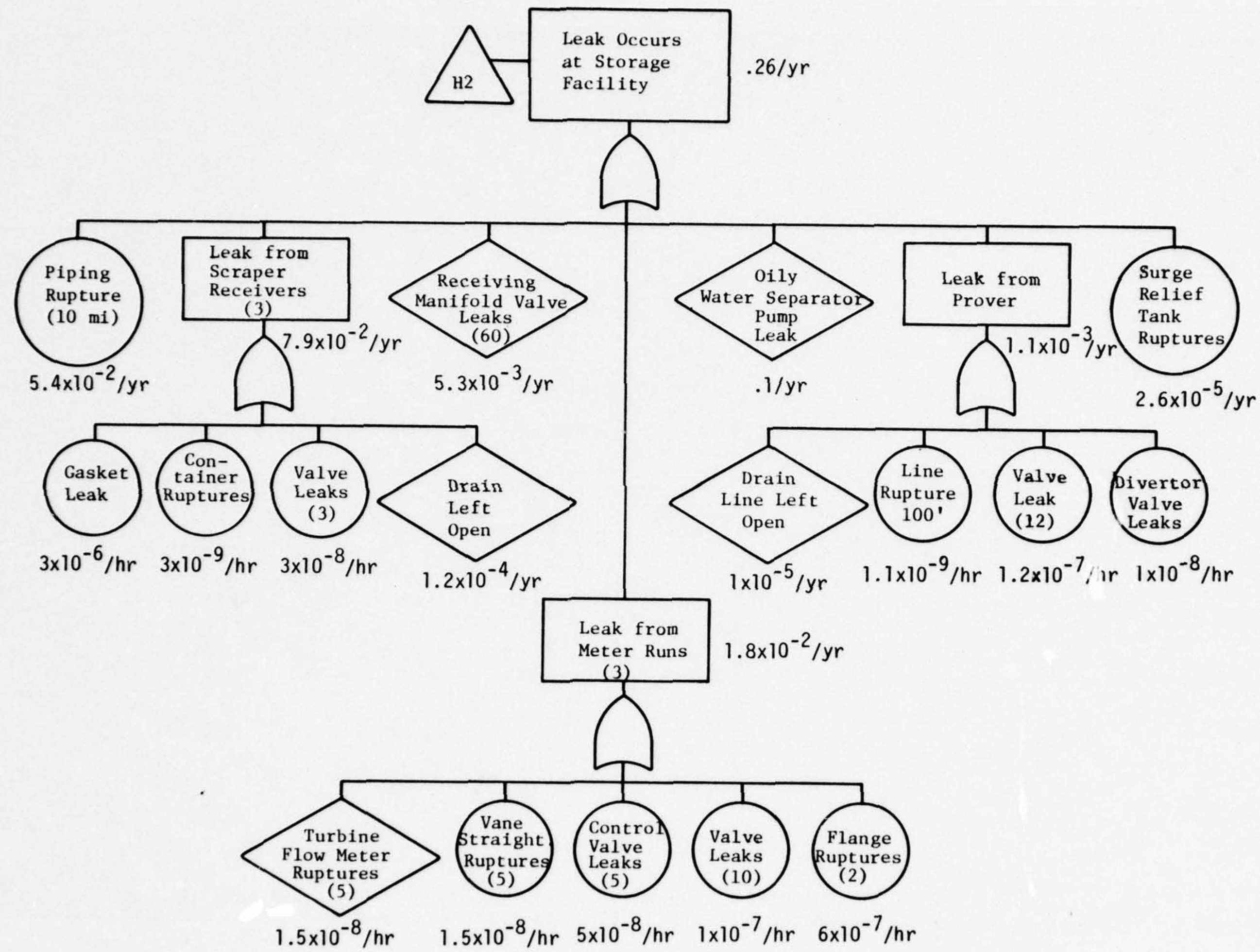

Figure 3-18. Fault Tree H2, "Leak Occurs at Storage Facility"

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Table 3-13

FAILURE EVENTS

SINGLE FAILURE EVENTS

1. Leak from topside line on a ship which spurts over the side or overflows the coaming.

2. Floating and submerged hose failures: gasket leaks, liner collapse, etc.

3. Ship collision with CALM buoy.

4. Leaks from SPM: swivel leaks, hose leaks, piping leaks, and valve leaks.

5. Any pipeline for SPM, offshore, or onshore pipelines: cracks, wild failures, external damage.

6. Events which damage the structural integrity of the pumping platform and the OTS: earthquake, explosion, collision by ship, corrosion.

7. Rupture of the Sea Sump or Oily Water Sump.

DOUBLE FAILURE EVENTS

1. Shipboard events: spill through open scuppers or over scuppers from leak in tank manifold, topside line, or expansion joint.

2. Flange and butterfly valve failure at the tail hose.

3. Swivel seal leaks for a double seal arrangement on SPM.

4. Leaks from the pumping platform waste disposal system and holes in decking.

5. Leak from the booster pumping station and containment dike (may not result in a spill onto water).

Table 3-13 (continued)

TRIPLE FAILURE EVENTS

1. Shipboard events: leak from the hose-ship connection into the drip pan, then through open scuppers or over the barrier.

2. Ship breakout.

3. Leak from the pumping platform OTS and failure of the waste disposal system (oily water pump overflow and skimmer overflow).

4. Leak at the storage facility and failure of primary and secondary containment.

3.4 OIL SPILL RISK

This Section presents the risk of oil spills from the deepwater port complex, described in Section 2.4, and assuming design and operating practices prevailing during the period 1965-1971. The frequency of spills was developed in the analysis presented in the preceding section. However, potential environmental damage also depends on the size of the spill. Spill sizes in coastal areas have been categorized by the National Contingency Plan as:

- Minor Spill - less than 10,000 gallons (238 bbls)
- Medium Spill - between 10,000 and 100,000 gallons
- Major Spill - greater than 100,000 gallons (2,380 bbls)

Spills occurring via the several mechanisms depicted for the several subsystems of the OTS in the Fault Trees B1 through H1 in Section 3.3 are summarized in Table 3-14. This listing also includes an estimate of the likely size of spill: minor, medium, and major as defined above. In addition, the table includes an estimate of the nominal largest spill from the several sources. This estimate is based in part on assumptions as to how the port will operate (e.g., frequency of pipeline inspection, accuracy of flow meters, emergency shutdown time, etc.), the calculated volumes of pipelines and spill size data for offshore platforms.

As a measure of relative risk, attempting to account for both size and frequency, Table 3-14 also lists the product of spill frequency and the value of the nominal largest spill. This value is similar to the statistical expectation quantity, but is not, because of the unavailability of an actual spill size distribution. It should be borne in mind that the value may have a large uncertainty, perhaps as much as an order-of-magnitude. On the other hand, the product is a useful, relative measure for risk since it approximates an accepted generalization that an equivalent volume of smaller spills, spread out in time, is likely to be just as environmentally damaging as a single large spill.[15]

The derivation of the values presented in Table 3-14 is discussed in the paragraphs below.

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Table 3-14

RELATIVE RISK OF OIL SPILLS FROM THE OIL TRANSFER SYSTEM

Source and Mode (Fault Tree)	Frequency (per Yr)	Spill Size	Nominal Size (bbls)	Risk (bbls/year)
Ship (B1)	0.14	Minor, Medium	333	47
Hose Strings Not During Offloading (C1)				
Leaks	0.24	Minor	15	3.5
Rupture	0.09	Minor, Medium	1500	135
Hose Strings During Offloading (C1)				
Leaks	13	Minor	25	310
Rupture	0.6	Minor, Medium, Major	4800	2880
SPM Unit CALM (D1)	2.65	Minor	25	66
	0.15	Minor, Medium, Major	5000	750
SPM Unit SALM (D1)	1.2	Minor	25	30

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Table 3-14

RELATIVE RISK OF OIL SPILLS FROM THE OIL TRANSFER SYSTEM (cont.)

Source and Mode (Fault Tree)	Frequency (per Yr)	Spill Size	Nominal Size (bbls)	Risk (bbls/year)
SPM Pipeline During Offloading (E1)				
Leaks	9.0×10^{-4}	Minor, Medium	2000	0.9
Rupture	3.8×10^{-4}	Minor, Medium, Major	26,800	10
SPM Pipeline Not During Offloading (E1)				
Leaks	2.5×10^{-3}	Minor	Seep	—
Rupture	1.6×10^{-3}	Minor, Medium, Major	21,000	26
Pumping Platform (F1)				
OTS and Waste System Fails	5.3×10^{-5}	Minor	50	3×10^{-3}
Waste System Leaks (F5)	8.8×10^{-5}	Minor	50	4×10^{-3}
Damage to Platform	5.3×10^{-4}	Minor, Medium, Major	4000	2.1

Table 3-14

RELATIVE RISK OF OIL SPILLS FROM THE OIL TRANSFER SYSTEM (cont.)

Source and Mode (Fault Tree)	Frequency (per Yr)	Spill Size	Nominal Size (bbls)	Risk (bbls/year)
Platform-to-Shore Pipeline (G1)				
Leaks (During Pumping)	0.034	Minor, Medium	1,000	34
Rupture	0.01	Minor, Medium, Major	100,000	1,000
Onshore Pipeline (G1)				
Leaks (During Pumping)	0.032	Minor, Medium	1,000	32
Rupture	0.01	Minor, Medium, Major	100,000	1,000
Spill from Onshore Facilities (H1)				
Leaks	3×10^{-5}	Minor, Medium	1,000	0.03

The frequency of spills from the components of the OTS on the tankship is developed on Fault Tree B1 in Section 3.3. The drip pan beneath the ship's manifold and the coaming (scuppers plugged) usually will retain the oil from most leaks from the shipboard components of the OTS, especially during the connection or disconnection of the hoses. However, it is likely these devices would be ineffective to prevent a spill onto the sea from larger leaks and spurts of oil such as caused by the rupture of an expansion joint. For the nominal largest spill, the expansion joint or gasket in a line carrying 50,000 bbl/hr was assumed to rupture. This would be noticed immediately, and a two-minute emergency shutdown period was assumed to be required. However, the design of flanged connections and expansion joints are such that only a portion of the flow can escape; this was assumed to be 20 percent of the full flow. Thus

$$0.2 \times 50{,}000 \times \frac{2}{60} = 333 \text{ bbls spilled.}$$

Spills from the floating hoses can occur during an offloading operation or between ship calls if the hoses are filled with oil. For the latter case the maximum volume of oil which could be lost is the total volume of the hoses, 1460 bbl (two 24-inch, 1,330-ft long hoses). An accident which causes both hoses to be severed, such as being cut by a passing vessel, poses an oil spill risk of

$$\frac{2.2 \times 10^{-6} \text{ events}}{\text{hour}} \times 40{,}150 \text{ hrs/yr} \times \frac{1500 \text{ bbl}}{\text{event}} = 135 \text{ bbl/yr.}$$

The spill frequency is given on Fault Tree C1, and the hoses remain unused for 40,150 hours total for 6 SPMs.*

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*For 6 SPMs, there are 6 x 8760 = 52,600 hours per year, but with 776 deliveries per year, and with 16 hours offloading time for each, the total SPM idle hours per year are

$$52{,}600 - (776 \times 16) = 40{,}150.$$

Small leaks, such as from gaskets or from nipple-liner interfaces also contribute to the risk of oil spills from hoses. It is possible that the hoses would be filled with oil and uninspected for a maximum of 48 hours, so small leaks could be undetected during that time. It is assumed that idle hoses will be kept under a small pressure, say 15 psig, as now recommended by several operators of SPMs. Thus leakage would occur until the pressure were relieved. According to the OCIMF's Buoy Mooring Forum Hose Guide, hoses which elongate more than 2 percent under this internal pressure must be removed from service. Therefore, it is assumed that the maximum amount of oil that could leak from a hose string in the idle state is 730 bbls x 0.02 = 14.6 bbls. The probability of this occurring, the product of the frequency of a small leak, the number of hours the hoses are idle, and the percentage of time the hoses are full of oil. Therefore, the frequency of a spill leak for 6 SPMs is

$$\frac{6 \times 10^{-6}}{\text{hr}} \times \frac{40150 \text{ idle hrs for 6 SPMs}}{\text{year}} = \frac{0.24 \text{ spills}}{\text{year}} .$$

The oil spill risk is 0.24 x 14.6 = 3.5 bbls/year.

During transfer, the volume of oil which could be spilled due to an accident is potentially greater, but vigilant observation of the process would reduce the volume that may be lost. A catastrophic failure of both hoses during transfer, such as caused by ship breakout, would cause a total volume to be lost:

Volume lost = Volume in hoses (1460 bbl)
+ Volume pumped out prior to detection (1667 bbls/min pumping rate)
+ Volume pumped out during shutdown (1668 bbl)

The last volume assumes that emergency shutdown requires 1 minute. For instantaneous detection, the volume lost would be 3128 bbl; for a one-minute interval prior to detection, the volume lost would be approximately 4800 bbl. Assuming an average detection interval of one minute*, the oil

*The maximum detection time for a large spill at the Durban SPM was two minutes.

spill risk due to catastrophic hose failure during transfer is

$$\frac{0.6 \text{ events}}{\text{DWP-yr}} \times \frac{4800 \text{ bbl}}{\text{event}} = 2880 \text{ bbl/yr}.$$

Hose component failures which result in leaks from cracks or holes also would contribute to oil lost during transfer. A hole of area 1 in^2 in a hose would cause

$$\frac{50{,}000 \text{ bbl}}{\text{hr}} \times \frac{1 \text{ in}^2}{\pi 12^2 \text{in}^2} = 110 \text{ bbl/hr}$$

to be spilled. A hole 1/8" in diameter would cause

$$\frac{50{,}000 \text{ bbl}}{\text{hr}} \times \frac{1/16^2 \text{in}^2}{12^2 \text{in}^2} = 0.43 \text{ bbl/hr}$$

to be spilled. Hoses are to be inspected visually every 30 minutes during transfer*, but due to adverse conditions small spills of this magnitude might not be detected for several 30-minute intervals. Hence, a spill size of 25 bbl/event was assumed for this type of failure. The risk then is

$$\frac{12.4 \text{ spills}}{\text{DWP-yr}} \times \frac{25 \text{ bbl}}{\text{spill}} = 310 \text{ bbl/yr}$$

Spills from the OTS components of the mooring itself are leakages from swivel seals, piping and the underbuoy hoses for the CALM. Most of these leaks are expected to produce only minor spills with 25 bbls being the nominal maximum, assuming regular 30-minute inspections during oil transfer. However, a few large spills also are expected, mainly from the rupture of the underbuoy hoses of the CALM. The nominal size of these spills was estimated to be 5,000 bbls (see the above discussion on hose ruptures). From the fault trees, the frequency of leaks is 2.8 and 1.2 per year for the CALM and the SALM, respectively. For the CALM, leaks from the underbuoy hoses account for 1.5 spills per year, and of these, 10 percent

*Part of the operating procedures indicated for LOOP.

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or 0.15 spills per year were assumed to be ruptures. Thus, the risk values are

$$\frac{2.65 \text{ spills}}{\text{year}} \times 25 \text{ bbs} = 66 \text{ bbls/yr}$$

and

$$\frac{0.15 \text{ large spills}}{\text{year}} \times 5{,}000 \text{ bbls} = 750 \text{ bbls/yr}$$

for the CALM, and

$$\frac{1.2 \text{ spills}}{\text{year}} \times 25 \text{ bbls} = 30 \text{ bbls/yr}$$

for the SALM.

Spills from the pipeline between the SPMs and the pumping platform may occur both during offloading and while the SPMs are idle. On the average, the former occurs 24 percent of the time, and the latter 76 percent (see footnote on page 3-66). From Fault Tree E1, the total frequency of spills of all types is 5.3×10^{-3} per year. The data in Figure 3-3 suggest that approximately 70 percent of the spills (leaks) will be minor or medium, whereas 30 percent will be major (ruptures). Thus the frequency of "leaks" is estimated to be $0.7 \times 5.3 \times 10^{-3} = 3.7 \times 10^{-3}$ per year and the frequency of "ruptures" is estimated to be $0.3 \times 5.3 \times 10^{-3} = 1.6 \times 10^{-3}$ per year. Because of the lack of surveillance of these pipelines, it is estimated that as much as 1,000 bbls could be leaked before being noticed and the operation shutdown (approximately the median spill size from large diameter pipes). Hence the risk value for leakage during offloading is

$$0.24 \times 1{,}000 \text{ bbls} \times 3.7 \times 10^{-3} \text{ per year} = 0.89 \text{ bbs/yr.}$$

For a pipeline rupture, it was assumed that the volume of oil contained in the 8,000 feet of pipeline, 21,000 bbls, would be lost together with that pumped out during the time required to detect the leak and to effect an emergency shutdown, estimated to be 5,000 bbls (see page 3-67). The total is 26,000 bbls and the risk value is

$$0.24 \times 26{,}000 \text{ bbls} \times 1.6 \times 10^{-3} \text{ per year} = 10 \text{ bbs/yr.}$$

During idle periods, leak-type failures in the pipeline likely would cause little loss of oil because of the lack of pressure. However, for a rupture type of failure, most of the entire volume of the pipeline, 21,000 bbls, could be lost. Hence the risk value is

$0.76 \times 21{,}000$ bbls $\times\ 1.6\times10^{-3}$ per year = 26 bbls/yr.

For the pumping platform, Fault Tree F1, three modes of spillage are possible:

1. A leak in the OTS and a failure of the oily water waste treatment system;

2. A leak from the waste treatment system itself; and

3. Damage to the platform structure and rupture of an OTS compoent.

The first mode has a frequency of 7.9×10^{-5} spills per year, and based on experience with offshore drilling and production platforms, the nominal maximum spill should be about 50 bbls.[11] Hence the risk value is

5.3×10^{-5} per year x 50 bbls = 3×10^{-3} bbls/yr.

For the second mode, the frequency is 8.8×10^{-5} spills per year and from the same reference a spill may be as much as 50 bbls. Hence the risk is

8.8×10^{-5} per year x 50 bbls = 4×10^{-3} bbs/yr.

For the third mode, the frequency is 3×10^{-4} spills per year, being caused primarily by ship collisions with the platform and fires and explosions. These are likely to be more catastrophic accidents causing larger spills. Assuming the accident occurs during offloading, it is estimated that as much as 3,500 bbls could be lost during emergency shutdown and as much as 460 bbls could be lost from emptying of broken pipeline (150 feet of 56-inch OD pipe). The total is approximately 4,000 bbls. Hence the risk value is

5.3×10^{-4} per year x 4,000 bbls = 2.1 bbls/yr.

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Large leaks from the pipeline between the pumping platform and the onshore facilities are detected by instrumentation and monthly checks by aircraft.* Due to the large volume of oil in each offshore pipeline ($4x10^5$ bbs), any leak which results in the loss of a significant portion of the contents of the line causes a major spill. An event such as being damaged by a ship's anchor could cause a major break in a pipeline. However, unless such a break were to occur close to shore, much of the oil could become trapped in the "high" portions of the line (near shore and the risers on the platform). Hence, it is assumed that as much as 100,000 bbls could be lost.**

"Medium-size" breaks, such as those which might develop from crack growth, are also detected by instrumentation. With a turbine meter accuracy of 1.0 percent, 1000 bbl/hr could go undetected by the instruments on an instantaneous basis (a leak of 1000 bbls also is approximately the median size of spills from large diameter pipes, Figure 3-3). However, the discrepancy would be detected after a period of time, about one hour, via the totalizing of the flow rates. Proceeding as above for the SPM pipelines, the frequency of all spills from the offshore pipelines is 0.034 per year (Fault Tree G1), and it is assumed that these resolve into 0.024 "leaks" per year and 0.010 "ruptures" per year. Hence the spill risk from "ruptures" is

$$\frac{0.010}{\text{year}} \times \frac{1 \times 10^5 \text{ bbls}}{\text{event}} = 1{,}000 \text{ bbls/year.}$$

The spill risk from "leaks is

$$\frac{0.024}{\text{year}} \times \frac{1{,}000 \text{ bbls}}{\text{event}} = \frac{24 \text{ bbls}}{\text{year}} .$$

---

*This pipeline is 43 miles long, 22 miles offshore, underwater, and 21 miles onshore to the storage terminal.

**Table 3-9 lists a spill of 160,000 bbls caused by a dragging anchor.

Detection of smaller leaks from pipelines depends on visual detection from an aircraft. This method assumes that the leak rate is sufficient to cause an oil spill which is visible at the time of the overflight, but due to myriad of contributing factors, leaks with rates smaller than those detected by instruments may go undetected for extended periods, but with small total volume spilled.

The occurrence of spills and leaks from the onshore segment of the pipeline are expected to be similar. However, because of their slightly shorter length than that of the offshore pipelines, 21 miles versus 22 miles, the spill frequency and relative risk values are slightly less.

From the Fault Tree H1, the expected frequency of spills from the components inside the booster pumping station and the storage facility are predicted to be 0.3 and 0.28 per year, respectively. The causes of these spills would be corrosion, gasket leaks, weld failures, etc., and because of their location, early detection is expected. However, it is assumed that these facilities would be well designed and would operate according to a well-executed SPCC plan, as required by EPA regulations (40 CFR 112). According to these regulations, all oil-containing components would be diked or curbed with drainage into catchment basins. The failure of these secondary containments is predicted to be infrequent and the loss of oil to the environment outside the facilities is predicted to be only 6×10^{-4} per year. Assuming an average spill size of 1000 bbls (the approximate median of spills exceeding 50 bbls from U.S. pipelines), the relative risk value is

$$6 \times 10^{-4} \frac{\text{spills}}{\text{year}} \times 1{,}000 \text{ bbls} = 0.6 \text{ bbls.}$$

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4.0 GUIDELINES AND CRITERIA FOR INSPECTION PROCEDURE AND EVALUATION

4.1 SELECTION STRATEGY

The ultimate objective of this study requires the selection of cost-effective inspection methods and procedures to minimize polluting oil spills. The strategy for accomplishing this involves four steps of which the preceeding analysis in Sections 3.3 and 3.4 constitute the first. By that analysis, the risk of oil spills from the several components of the Oil Transfer System has been established.

The second step is a re-examination of the fault trees to determine the chief causes and failure modes leading to the spills. Table 3-13 also is useful for this. This examination includes identifying causes that can be controlled by inspection with the objective of reducing risk by reducing the frequency of oil spills. An alternative is to assess the possibility of reducing risk by a monitoring technique which limits the quantity of oil spilled in a mishap. An example of the former is a pre-transfer inspection of the hose strings for leaks with a non-polluting fluid. An example of the latter is a continuous monitoring of the hoses during transfer to detect a leak. If a leak is detected, the oil spill risk could be reduced by initiating immediate shutdown of the hose string involved. This study deals only with effective detection of a problem or an incipient problem, and not with the action to be taken if a problem is detected.

Having identified the parts of the oil transfer system most vulnerable to oil spills, the third step consists of identifying candidate inspection methods and procedures for those parts. The identification is to consist of a thorough survey of methods and procedures together with a culling, based on analysis of the likely effectiveness and judgement of the likely cost. The survey will emphasize state-of-the-art techniques, but will consider future techniques which seem to have promise of being implementable in the near term. Determination of effectiveness must be as quantitative as possible and utilize all available data pertaining to

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reduction of mishap frequency.

The fourth step deals with estimating the cost of implementing the selected techniques, including capital cost, rental, labor and any facility downtime. Finally, a comparison between cost and effectiveness of risk reduction is made to determine the most efficient inspection techniques.

Based on the results presented in Section 3.4 and Table 3-14, the following subsection identifies the major causes of oil spill risk which are subject to control via inspection. This accomplishes step 2. The last two subsections deal in more detail with aspects of the remaining steps in the selection of inspection techniques.

4.2 RELATIVE RISK CONTRIBUTIONS

This section discusses the relative risks of oil spills from the Oil Transfer System together with the causes of the spills. The purpose is to establish priorities for inspection of components and subsystems with respect to their vulnerability to oil spill risks.

The ranking is presented in Table 4-1 and is based on the relative risk values listed in Table 3-14. The risk values were divided into four ranges: >100, 10-100, 1-10 and <1 bbl/year. The values within each range are judged to be equivalent; the uncertainties in the data and estimates used to develop the values do not justify further resolution. Table 4-1 also lists the chief causes of the oil spills as determined from examination of the fault trees. The following paragraphs discuss the spill risks and indicate the general type of inspection procedure for the OTS which seems to be appropriate for reducing risk.

According to the data in Table 4-1 the greatest risk arises from various failures of the integrity of the hose strings, the platform-to-shore pipeline and the onshore pipelines. The reason for the high risk from the first is a very high frequency (13 per year) of minor spills and a somewhat lower frequency (0.6 per year) of medium and major spills, both occuring

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Table 4-1. Ranking of Components of the Oil Transfer System Vulnerable to Oil Spills

Relative Risk (bbls/year)	Systems	Principal Components and Causes
>100	Hose String (During Offloading)	Ship Breakout because of mooring failure, especially the hawsers.
		Miscellaneous leaks, especially in area nipple-hose connection. Faulty connection or gaskets between hose segments also may contribute.
	Platform-to-Shore Pipeline	Pipeline damage by outside activity (e.g., dragging anchor), corrosion and failures such as torn pipe seam.
	Onshore Pipeline	Pipeline damage by outside activity (e.g., excavation and construction equipment) and failures such as defective welds and corrosion.
10 to 100	Hose String (Not During Offloading)	Hose string damaged by external activity such being cut by a maneuvering vessel.
	SPM Unit (CALM)	Miscellaneous leaks from the product distribution unit, PLEM, gaskets and seals.
	SPM Unit (SALM)	Leaks from the fluid assembly and hose swivel seals; to a lesser extent gasket leaks on the PLEM.
	SPM Pipelines (Not During Offloading)	Damage by outside activity (e.g., dragging anchor), corrosion and failures such as torn pipe seam.
	Plateform-to-Shore and Onshore Pipelines	Leaks from failures such as corrosion, and defective welds.
	Connections and Pipelines on Tankship	Large breaks in expansion joints, tank piping and manifolds.

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Table 4-1. continued

Relative Risk (bbls/year)	Systems	Principal Components and Causes
1 to 10	Hose Strings (Not During Offloading)	Miscellaneous leaks from flange and swivel seals, the hose, etc.
	SPM Pipelines (During Offloading)	Damage by external activities (e.g., dragging anchor), corrosion and failures such as torn pipe seam.
	Pumping Platform	Damage to platform structure from fire and explosives, ship collision and failure of supports.
<1	SPM Pipeline (Not During Offloading)	Leaks from failures such as corrosion and defective welds.
	Pumping Platform	Failures and leaks from the Oily Water Waste Treatment System together with leaks from OTS components on the platform.
	On Shore Facilities	Leaks from cracked piping and valves, gaskets and operational accidents.

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during offloading.

The former spills are associated with various types of leaks from the hoses which have been experienced by SPM operators in the past. These include holes and cracks presumably associated with the several hose problems identified by the Southwest Research Institute study[4] such as nipple-hose bond failure, liner failure, etc. Also included by implication are leaks through gaskets between the flanges of adjacent hose segments (acknowledged as a source of leaks by one SPM operator). The larger spills are associated with catastropic failures of the hoses during offloading, caused in turn, by a failure of the mooring system, especially the mooring hawsers. As discussed in Section 3.1, this dominance of the hose string (and to a lesser extent the mooring hawsers), for oil spill risk, is generally consistent with the experience of SPM operators.

Because of the high frequency of spills from the hose strings a good control strategy appears to be inspection techniques which will indicate a faulty condition before a leak or spill has occurred. This approach already has been adopted, in part, by OCIMF and terminal operators in their promulgation of standards for manufacturing quality control, hose handling techniques and operational procedures. Besides the hoses, inspection techniques also are needed to insure a much lower frequency of failure for the mooring hawsers.

For the platform-to-shore and onshore pipelines, very large spills are possible but the frequency (0.016-0.017 per year) is very much less than for hoses. Because of the lower spill frequency it may be more appropriate in this case to adopt means for immediate detection of a pipeline rupture and an emergency procedure to limit the amount of oil which can escape from the broken line. During use of the pipeline, a rupture would be detected rapidly by custodial flow monitoring equipment ashore and on the pumping platform. However, detection means also are needed when the pipeline is idle but full of oil.

As may be noted in Table 3-9, a major cause of large breaks in pipelines is "third party" activities. For onshore pipelines this usually is construction and excavation activities. For undersea pipelines the "third party" activity usually has been a dragging achor. In the future, according to recent OPSO regulations (49 CFR 195.248), offshore pipelines are to be buried with a cover of 30 to 40 inches, depending on the location. With these depths of cover, it is likely that most dragging anchor accidents would be precluded. Hence a major need for inspection is to insure that the cover is maintained continuously and has not been erroded away by ocean currents. The pipelines also may rupture as the result of general deterioration, such as corrosion and the failure of seams and joints. Here inspection to detect incipient failure is important.

This highest risk catagory also includes the underbuoy hoses of the CALM SPM. These hoses are subject to the same types of failures that are prevailant for the floating hoses. However the underbuoy hoses generally are damaged less frequently by external causes such as the failure of the mooring system or collision with a vessel.

The next lower risk range (10-100 bbls) includes incidents involving the hoses and SPM pipelines while they are idle, leaks from the SPM units and the platform-to-shore pipelines, and breaks in the piping and connections on the tankship. The first involves "third party" damage which would result in a large breach in the hose string or the SPM pipeline. Neither accident is predicted to occur very frequently, but a rupture of the hoses could result in a medium spill whereas rupture of an SPM pipeline could result in a major spill. Inspection of the OTS is not an appropriate technique for preventing such accidents. However, monitoring some parameter such as pressure in order to detect automatically such breaks and to initiate some mitigating action could be worthwhile. Leaks from the SPM units are expected to be small but rather frequent (1.2 to 2.7 per year). Here the best approach likely is to use techniques which alerts the operator to deteriorating items such as seals and gaskets through which leaks may develop. Leaks

from the platform-to-shore and onshore pipelines are predicted to be somewhat less frequent (0.022-0.024 per year) but the volumes lost may be substantially greater. Here both approaches may be valuable: first, the frequent use of special pigs to check corrosion, the integrity of welds and seams, etc., and thereby reduce the frequency, and second, more sensitive leak detection techniques to minimize the oil lost before detection. Passive acoustic techniques may be appropriate for both approaches. Spills from the tankship occur primarily from large leaks, such as a ruptured pipe expansion joint which overlfows the coaming.

The risk range of 1 to 10 bbls/year consists of leaks from the hose strings while idle, rupture of the SPM pipelines during offloading, and damaged caused to the platform by explosions and vessel collisions. Hose leaks while idle are predicted to be fairly frequent (0.15 per year) and could be controlled by the same inspections performed to reduce the incidence of leakage while offloading. Rupture of the SPM pipelines by both external and internal (e.g., defective pipe seam) factors are predicted to be infrequent (3.8×10^{-4} per year) but the potential volume of the spill is substantial - a major spill is possible. As for the platform-to-shore pipelines, the best approach may be to use monitoring techniques which indicate the breach immediately and which initiate effective measures to limit the loss of oil. Spills caused by fire and vessel damage to the platform are predicted to be infrequent but major spills could result. Here inspection techniques can be used to reduce the frequency of fires (e.g., sensors to detect the accumulation of flammable vapors), and to perhaps limit the loss of oil.

Leaks from the SPM pipeline (while idle), leaks and spills from the pumping platform and leaks from the on-shore booster pumping station and storage facility comprise the lowest risk range. Because of their low risk, spills from these sources do not seem to merit special attention. However, the reason for the low risk are the use of secondary containments. On the pumping platform, leaks, spills and large losses of oil from the OTS would be contained by the curbed steel decking, the deck drains and the oily water sump. Similarly, leaks and spills from components of the onshore OTS would be contained by one or more berm dikes. Without these containments the risk of oil spills from these sources would be approximately

the same as from the SPM units or portions of the pipelines. Thus inspection to insure the maintenance of the integrity of these containments is nearly as important as those for the OTS itself.

Finally it should be noted that the risk ranking presented in Table 4-1 reflects actual spill experience for similar components and facilities. Spills from other sources and via mechanisms other than those mentioned do pose a threat but generally are not experienced. The reason may be the present, general use of certain inspection methods that prevent these spills. For example, offshore structures and platforms could collapse because of badly corroded supports. However, this has not occurred because of vigilant inspection and maintenance programs to prevent corrosion. Therefore, to be complete, an inspection pgoram for U.S. deepwater ports must include these generally practiced inspections.

4.3 POTENTIAL FOR RISK REDUCTUION BY INSPECTION

The reduction of the risks of oil spillage and pollution may be accomplished using two general approaches:

- Periodic inspection to reduce the frequency of accidential spills;
- Continuous or frequent inspection (monitoring) to detect the occurrence of a leak.

As may be seen from an examination of Table 3-14, the risk of oil spills from the various subsystems of the OTS generally may be ascribed to a relatively high frequency (e.g., the floating base strings) or a potentially large-volume oil spill (e.g., underwater pipelines). Inspections to reduce the frequency of leaks and spills include periodic examination of individual components to check their performance and condition for service. The intention is to detect conditions which will eventually lead to a leak before the leak actually occurs. The examinations may consist of both visual observation and the performance of one or more instrumented tests. The results of the examinations, when compared with previously established criteria, determine suitability for continued service, repair or replacement. The criteria generally are derived from the manufacturer's recommendations and the user's experience. Examples of such inspections are: the visual examination of the completed, flanged connection between the hose and ship

manifold; pressurizing the hose and checking for leaks; routine maintenance of valves, pumps and strianers on the pumping platform; pigging the pipelines to check wall thickness, condition of welded joints and the extent of corrosion.

Continuous monitoring, to detect the occurrence of leaks and initiate shutdown to limit the amount of oil spilled, includes visual and instrumented observations. An example is the comparison of the flows at both ends of a pipeline. Such inspections are an important approach to reduce the risk of spills from "third party" damage (e.g., a ship dragging its anchor and damaging a pipeline). Also such inspections can serve as a backup for the inspections to reduce spill frequency, described above.

An important consideration for periodic inspections is the length of time between each inspection. Practice makes this a trade-off between the cost and resources required for the inspection and the anticipated likelihood of failure. Application of this practice will not eliminate failures of equipment and spills but will insure a low frequency of spills consistant with the costs and consequences of an oil spill. According to theory (References 3 and 13), the likelihood of a leak depends on the probability that one or more components of a system is in a failed state (e.g., a collapsed hose liner or a hole in the pumping platform dock). This latter probability, in its simplest form, is the product of the failure rate and the length of time the failure can remain undetected. If the system is inspected periodically, the detection time, on the average, is one-half the interval between inspections (References 3 and 13). Thus failure probability decreases in direct proportion to frequency of inspection.

The above theory applies primarily to random failures of equipment, those which normally occur during steady-state operations. Two other types of failures also usually are distinguished, wear-in failures and wear-out failures (Reference 3). The likelihood of occurrence of these failures too may be reduced by inspection but the relationship between inspection interval and likelihood is not so clear-cut as for random-type failures.

Finally, with respect to DWP's, it should be noted that the failure rates for many critical components, such as the floating hose strings, are not known. Instead only a frequency of hose-caused spills was

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determined (see Section 3.2). Hence, utilization of the above mentioned theory to determine the effect of inspection frequency on the occurrence of these types of spills will be difficult. However it appears feasible to estimate an upper and lower bound for the failure rates in these circumstances.

The components for which inspection (either periodic or continuous) can reduce the risk of oil spills are listed in Table 4-2. The list is organized by subsystem, and the subsystems are ranked according to the relative risk ranking in Table 4-1. Thus the components are in approximate priority for which new (relative to techniques commonly in use during the early 1970's) inspection techniques may have the greatest potential benefit. Thus the platform structure does not appear very high on the list, not because it isn't important but because existing inspection techniques seem to be adequate. New techniques to inspect platforms would not have a significant impact on oil spill risk reduction.

Additionally, some of the new inspection techniques most likely will include those introduced by industry since the early 1970's. In particular, industry presently regards the hoses (both floating and submerged) as the critical system with respect to vulnerability to oil spills. Since 1972, through the Buoy Mooring Forum of the Oil Companies International Marine Forum, a set of voluntary standards have been promulgated for

- construction and quality control for hoses,
- storage and handling of hoses,
- inspection of hoses.

Moreover, significant progress has been made in the design and section of DWP components and systems via:

- location studies to determine the environmental conditions;
- model tests to match the best type of system and components with the environmental conditions;
- site tests to verify the design and predicted behavior of the selected system.

Table 4-2

Inspectable Components and Subsystems

Systems and Components

Hose Strings

Hose Carcass, Nipple, Flange, Flange Gaseket, Flange Bolts, Floats, Butterfly Valve, Blind Flange.

Under Sea Pipeline

Pipeline, Cathodic Protection

Onshore Pipeline

Pipeline, Pumps, Checkvalve, Block Valves, Discharge Valves, Pressure Relief Valves, Cathodic Protection, Strainer.

SPM Unit - CALM

Product Distribution Unit and Seals, Outboard Piping, Outboard Swivel, Valves, Expansion Joints, Under Buoy Hose, Hose Floats and Buoyancy Tanks, Flanges, Gaskets and Bolts, PLEM Chamber, Check valve, Isolation Valve, Turntable Roller Bearing.

Anchor Chains and Anchors, Mooring Hawsers and Chafing Chains, Buoy, Cathodic Protection, Navigational Aids.

SPM Unit-SALM

Fluid Swivel Assembly and Seals, Hose Arm and Seals, Product Transfer Pipe, Base Hose, Flanges and Bolts, Gaskets, Check Valves, Isolation Valves, PLEM Chamber, Buoyancy Tanks Bumper Rail.

Mooring Hawsers and Chafing Chains, Mooring Braket, Buoy, Universal Joints, Anchor Chain, Chain Swivels, Riser Shaft, Base coupling and Universal Joint, Mooring Base, Piles, Scour Protection, Cathodic Protection.

Tankship

Expansion joints, Spool Piece, Gaskets, Shutoff Valve, Drip Pan, Plugged Scuppers, Hoisting Gear and Hose Support.

Pumping Platform

Riser Pipes, Manifolds and Piping, Valves, Check Valves, Relief Valves, Air Eliminator, Samplers, Strainers, Pumps, Flow Meters, Meter Prover, Pig Launchers.

Deck and Curbing, Deck Drains, Platform Structure

Reclaimed Oil Tank, Maintenance Oil Drain Tank, Skimer Tank, Oily Water Sump, Oily Water Separator, Pumps, Valves, Piping, Drain Lines Level Switches, Atmosphic Vents, Sea Sump.

Onshore Terminal

Pipelines, Pig Receiver Traps, Check Valves, Valves Strainer, Flow Meters, Meter Prover, Relief Valves.

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DWP operators claim that by implementing these design and procedures standards, their problems have been greatly reduced. The downtime of their terminals for unscheduled repairs has been reduced by at least 50 percent. Nevertheless the operators still admit to frequent problems with hoses. Even allowing their estimate of a 50 percent reduction in unscheduled repairs and assuming further that these were made necessary because of leaks, this would suggest only a corresponding 50 percent reduction in the risk of oil spills from hoses. Applying this reduction to the values listed in Table 3-14 still leaves the risk at a very high level relative to the other components of the OTS.

In spite of improvements made between 1970 and 1977, there remains a high potential for oil spill risk reduction via thorough and regular inspections of the OTS, especially the hose strings, the undersea pipeline and the SPM units.

4.4 OTHER CONSIDERATIONS

Besides risk reduction, several other factors must be considered in the selection of inspection methods. Chief among these is cost -- cost of equipment, labor and downtime of the facility. Inspection methods which are obviously very expensive in any of these areas may be eliminated as candidates, especially if alternative methods are available. Inspections requiring shutdown of the DWP for a substantial length of time simply are not practical.

An operator of DWP will implement a program of inspection and maintenance not only to minimize oil spills but also (and perhaps, primarily) to insure continued efficient operation of the facility. Nevertheless it appears appropriate to judge the efficiency of inspection methods based on cost versus ability to reduce oil spills, cost-effectiveness. The fact that the inspection method may contribute to the reliability of the operation of the part should bear additional consideration.

In determining the cost of an inspection method, several options to the DWP operator must be considered. At one extreme, the

operator might own all required equipment and utilize his own employees. At the other extreme, the operator may rent all needed equipment or contract with a firm to perform all inspections. In practice, various combinations of employees versus contractors, and owned versus contractor or rental equipment would be used. For example, frequent and routine inspection, e.g., visual checks of the floating hoses and the SPM, may be most economically performed by employees. On the other hand, infrequent inspections, which require specialized equipment and training or personnel, e.g., underwater inspection of the SPM and pumping platform structure, likely would be most economically performed by a contractor.

The other factors besides cost include the following:

- Alternative inspection methods for the same component or subsystem should be available. Problems caused by weather, sea states, frequency of ship calls, availability of trained personnel, etc., may make some methods suitable for one site but not another;
- Some methods may be still in an early state of development and not fully field tested. This should not preclude their selection but assessment should be made of the method's likely effectiveness;
- Reliability of the method;
- The time and cost of maintaining inspection instruments and equipment;
- The level of training required for personnel using the method;
- Support facilities required for the method.

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6.0 GLOSSARY

CALM (Catenary Anchor Leg Mooring): A single point mooring which is anchored to the sea bed by multiple anchor chains, usually six in number.

DWP (Deepwater Port): An offshore facility for mooring VLCCs and transferring oil between an onshore storage facility and the VLCC.

DWT (Deadweight Tons): Total carrying capacity of cargo, bunkers, stores and crew; approximately equal to the cargo carrying capacity of a tankship.

ELSPM (Exposed Location Single Point Mooring): A SPM which is specially designed to survive waves of 20 meters and retain a moored tanker in waves of 6 meters.

Fluid Swivel: A component of an SPM which permits rotation of the hose strings about a fixed point.

FMEA: Failure Mode Effects Analysis

Hose String: The assemblage of individual sections of hose (floating or submarine) for transferring oil between the tanker and the SPM.

LOOP: A deepwater port oil transfer terminal complex proposed for installation off the coast of Louisiana.

Monobuoy: The floating component of a SPM.

OCIMF (Oil Companies International Marine Forum): An industry organization for sharing data and information concerning marine problems and for setting standards for marine equipment.

OPSO: Office of Pipeline Safety Operations, Department of Transportation.

OTS (Oil Transfer System): The system of a DWP for transferring oil, including the hose strings, the SPM, undersea pipelines, pumping platform, and onshore pipelines connecting to a storage facility.

PDU (Product Distribution Unit): A fluid swivel which can transfer more than one oil product.

PLEM (Pipe Line End Manifold): The manifold on the undersea pipeline, which connects to a SPM.

SALM (Single Anchor Leg Mooring): A single point mooring which is anchored through a single anchor leg or chain made fast to a fixed base located on the ocean floor.

SBS (Single Buoy Storage): A SPM containing a mooring system consisting of a rigid arm to which a floating storage vessel is permanently attached.

SEADOCK: A deepwater port oil transfer terminal complex proposed for installation off the coast of Texas.

SPAR: A large SPM which incorporates oil storage and production facilities.

SPM (Single Point Mooring): A generic term which includes all floating buoy mooring systems which permit a ship to rotate freely around them.

Tail Hose: That segment of a hose string which is connected to the ship's manifold. It normally is smaller in diameter, lighter and more flexible than the remainder of the hose string.

VLCC (Very Large Crude Carrier): A tanker with a capacity of approximately 180 to 400,000 deadweight tons.

Appendix A

CHARACTERISTICS OF EXISTING DEEPWATER PORTS WORLDWIDE

Source: Various

Country	Abu Dhabi*	Abu Dhabi*	Abu Dhabi*	Angola	Argentina	Argentina	Australia	Bangladesh
Location	Das Island	Mubarras Field	Abu-el Bu-Koosh	Cabinda	Puerto Rosales	Caleta Olivia	Botany Bay	Chittagong
Owner(s)/ Operator(s)	BP	Abu Dhabi Oil Co.	CFP	Gulf	YPF	YPF	Maritime Services Bd.	Port Authority
Designer	IMODCO	SBM	SBM	SBM	IMODCO	IMODCO	SBM	IMODCO
Tanker Size	300,000	200,000	100,000	100,000	40,000	60,000	120,000	45,000
Hose No. x Size (Inches)	2x24-in.+ 1x16-in.	1x24-in.	2x10-in.	2x16-in.	1x16-in.+ 1x12-in.	1x20-in.+ 1x12-in.	3x12-in.	1x12-in.
Year Installed	1972	1972	1975	1968	1970	1974	1970	1967
No. Moorings/ Type	CALM	CALM	SBS	CALM	CALM	CALM	CALM	CALM
Wind, % of Total								
0-1 knot	5	5	5	2	3	3	2	5
1-3 knots	11	11	11	8	7	7	6	11
4-10 knots	38	38	38	61	33	33	41	38
11-21 knots	26	26	26	23	35	35	41	26
22-33 knots	15	15	15	5	16	16	8	15
over 33 knots	5	5	5	1	6	6	2	5
Wave % of Total								
0-1 Ft.	32	32	32	4	9	9	17	7
1-3 Ft.	48	48	48	64	49	49	52	50
3-8 Ft.	14	14	14	29	40	40	29	37
over 8 Ft.	6	6	6	3	2	2	2	6
Current, Knots	0.6	0.6	0.6	0.8	0.7	0.7	0.5	0.6
Tidal Variation	10.4 FT	10.4 FT	10.4 FT	7 FT	12.8 FT	12.8 FT	23.3 FT	10.4 FT
Low Water Depth	94 FT	58 FT	97 FT	NA**	59 FT	113 FT	63 FT	NA**
Comments								Out of Service

*United Arab Emirates

** Information Not Available

Country	Borneo	Brazil	Brazil	Brazil	Brazil	Brunei	Canada	Chile
Location	Labuan	Tramandai	Tramandai	San Francisco	San Francisco	Seria	St. John, N.B.	Quintero Bay
Owner(s)/ Operator(s)	Shell	Petrobras	Petrobras	Petrobras	Petrobras	Shell	Irving Oil	Enap
Designer	SBM	SBM	SBM	IMODCO	IMODCO	SBM	SBM	SBM
Tanker Size	250,000	100,000	200,000	200,000	200,000	250,000	350,000	209,000
Hose No. x Size (Inches)	2x20-in.	2x16-in.	1x24-in.	NA	2x20-in.	2x20-in.	1x24-in.+	2x20-in.
Year Installed	1974	1968	1970	1974	1975	1971	1969	1971
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	CALM	Turn-table with heated dome for sub-artic service	CALM
Wind, % of Total								
0-1 knot	5	3	3	3	3	NA**	2	NA
1-3 knots	12	7	7	7	7		4	
4-10 knots	54	33	33	33	33		30	
11-21 knots	26	35	35	35	35		30	
22-33 knots	3	16	16	16	16		25	
over 33 knots	0	6	6	6	6		9	
Wave % of Total								
0-1 Ft.	17	9	9	9	9	NA	3	NA
1-3 Ft.	63	49	49	49	49		37	
3-8 Ft.	19	40	40	40	40		39	
over 8 Ft.	1	2	2	2	2		21	
Current, Knots	0.7	0.7	0.7	0.7	0.7	NA	1.3	NA
Tidal Variation	15.3 FT	12.8 FT	12.8 FT	12.8 FT	12.8 FT	NA	5.9 FT	NA
Low Water Depth	NA**	NA	NA	NA	72 FT	NA	147 FT	154 FT
Comments		**Information Not Available						

Country	Congo	Denmark	Dominican Republic	Dubai*	Dubai *	Ecuador	Ecuador	Egypt
Location	Djeno	North Sea Dun Field	Santo Domingo	Fateh field	Dubai	Porto Baleo	Porto Baleo	Ras-el-Sraqiq
Owner(s)/ Operator(s)	Elf Congo	Gulf/ Denmark	Shell	Dubai Pet.	Dubai Pet.	Gulf/ Texaco	Gulf/ Texaco	WEPCO
Designer	SBM	SBM	SBM	SBM	McDermott	SBM	SBM	SBM
Tanker Size	250,000	70,000	150,000	150,000	300,000	100,000	100,000	100,000
Hose No. x Size (Inches)	2x20-in.	1x12-in.+ 1x6 in.	2x16.in.+ 1x12-in.	2x16-in.	2x24-in.	2x20-in.+ 1x16	1x24-in.+ 1x20-in.	2x16-in.
Year Installed	1972	1971	1971	1969	1972	1971	1971	1968
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	CALM	CALM	CALM
Wind, % of Total								
0-1 knot	2	2	1	5	5	NA	NA	NA
1-3 knots	8	6	5	11	11			
4-10 knots	61	25	41	38	38			
11-21 knots	23	35	35	26	26			
22-33 knots	5	16	17	15	15			
over 33 knots	1	6	1	5	5			
Wave % of Total								
0-1 Ft.	4	5	2	32	32	NA	NA	NA
1-3 Ft.	64	54	49	48	48			
3-8 Ft.	29	32	45	14	14			
over 8 Ft.	3	9	4	6	6			
Current, Knots	0.8	0.5	0.7	0.6	0.6	NA	NA	NA
Tidal Variation	7 FT	7.2 FT	1.5 FT	10.4 FT	10.4 FT	NA	NA	NA
Low Water Depth	73 FT	150 FT	NA	NA	NA	124 FT	124 FT	NA
Comments								

*United Arab Emirates

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Country	Egypt	Egypt	Egypt	Egypt	Egypt	Egypt	Egypt	Egypt
Location	Suez	Suez	Suez	Alexandria	Alexandria	Alexandria	Alexandria	Alexandria
Owner(s)/ Operator(s)	Arab Pet.	Arab Pet.	Sumed	A.P.P.Co	A.P.P.Co	A.P.P.Co	A.P.P.Co	A.P.P.Co
Designer	IMODCO	IMODCO	SBM	IMODCO	IMODCO	SBM	SBM	SBM
Tanker Size	250,000	250,000	120,000	250,000	250,000	120,000	120,000	120,000
Hose No. x Size (Inches)	2x24-in.	2x24-in.	2x20-in.	2x24-in.	2x24-in.	2x20-in.	2x20-in.	2x20-in.
Year Installed	1976	1976	1974	1976	1976	1976	1976	1976
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	CALM	CALM	CALM
Wind, % of Total	NA	NA	NA					
0-1 knot				7	7	7	7	7
1-3 knots				14	14	14	14	14
4-10 knots				46	46	46	46	46
11-21 knots				21	21	21	21	21
22-33 knots				9	9	9	9	9
over 33 knots				3	3	3	3	3
Wave % of Total	NA	NA	NA					
0-1 Ft.				10	10	10	10	10
1-3 Ft.				53	53	53	53	53
3-8 Ft.				30	30	30	30	30
over 8 Ft.				7	7	7	7	7
Current, Knots	NA	NA	NA	0.4	0.4	0.4	0.4	0.4
Tidal Variation	NA	NA	NA	3 FT	3 FT	3 FT	3 FT	3 FT
Low Water Depth	105 FT	105 FT	NA	108 FT	108 FT	NA	NA	NA
Comments								

Country	Egypt	Egypt	France	Gabon	Gabon	Germany	India	India
Location	Suez	Suez	Frontignan	Gamba	Port Gentil	Cuxhaven	Bombay High	Bombay High
Owner(s)/ Operator(s)	A.P.P.Co	A.P.P.Co.	Mobil Oil Franciase	Shell	Shell	West German Navy	ONGC	ONGC
Designer	SBM	Imodco	IMODCO	SBM	SBM	IMODCO	SBM	SBM
Tanker Size	120,000	250,000	275,000	100,000	100,000	2,000	100,000	100,000
Hose No. x Size (Inches)	2x20-in	2x24 in	2x20-in.	1x16-in.	1x16-in.	1x4-in.	1x8-in. 1x16-in.	1x16-in. 1x8-in.
Year Installed	1975	1976	1973	1965	1967	1962	1975	1975
No. Moorings/ Type	CALM	2/ CALM	CALM	CALM	CALM	CALM	CALM	Permanent mooring of storage tanker of 100,000dwt SPM
Wind, % of Total								
0-1 knot	NA	NA	7	2	2	2	5	5
1-3 knots			14	8	8	6	11	11
4-10 knots			46	61	61	35	38	38
11-21 knots			21	23	23	35	26	26
22-33 knots			9	5	5	16	15	15
over 33 knots			3	1	1	6	5	5
Wave % of Total								
0-1 Ft.	NA	NA	10	4	4	5	7	7
1-3 Ft.			53	64	64	54	50	50
3-8 Ft.			30	29	29	32	37	37
over 8 Ft.			7	3	3	9	6	6
Current, Knots	NA	NA	0.4	0.8	0.8	0.5	0.6	0.6
Tidal Variation	NA	NA	3 FT	7 FT	7 FT	7.2 FT	10.4 FT	10.4 FT
Low Water Depth	82 FT	80 FT	102 FT	NA	NA	26 FT	240 FT	240 FT
Comments								

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Country	Indonesia	Indonesia	Indonesia	Indonesia	Indonesia	Indonesia	Indonesia	Indonesia
Location	Java Sea	Java Sea	Java Sea	Java Sea	Djatibar-ang	Ardjuna field	Ardjuna field	Bekapai field
Owner(s)/ Operator(s)	Arco	IIAPCO	IIAPCO	Arco	Pertamina	Atlantic Richfield	Atlantic Richfield	Total
Designer	McDermott	IMODCO	IMODCO	IMODCO	IMODCO	SBM	SBM	SBM
Tanker Size	45,000	55,000	55,000	145,000	150,000	200,000	200,000	100,000
Hose No. x Size (Inches)	1x8-in.	2x16-in.	2x12-in.+ 2x20-in.	2x20-in.+ 1x20-in.	2x20-in.+ 1x12-in.	2x20-in.	2x16-in.	2x8-in.
Year Installed	1971	1971	1972	1972	1972	1973	1973	1974
No. Moorings/ Type	CALM	CALM	CALM	Storage Vessel	CALM	CALM	Permanent mooring for storage tanker of 1,000,000 bbls.	Permanent mooring for a storage tanker of 100,000 dwt.
Wind, % of Total								
0-1 knot	5	5	5	5	5	5	5	5
1-3 knots	12	12	12	12	12	12	12	12
4-10 knots	54	54	54	54	54	54	54	54
11-21 knots	26	26	26	26	26	26	26	26
22-33 knots	3	3	3	3	3	3	3	3
over 33 knots	0	0	0	0	0	0	0	0
Wave % of Total								
0-1 Ft.	17	17	17	17	17	17	17	17
1-3 Ft.	63	63	63	63	63	63	63	63
3-8 Ft.	19	19	19	19	19	19	19	19
over 8 Ft.	1	1	1	1	1	1	1	1
Current, Knots	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Tidal Variation	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT
Low Water Depth	NA	120 FT	130 FT	135 FT	75 FT	138 FT	139 FT	117 FT
Comments								

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Country	Indonesia	Indonesia	Indonesia	Indonesia	Indonesia	Indonesia	Indonesia	Iran
Location	Java Sea	Kaliman-tan	Pang Kal-an Susu	Balik-pappan	Ardjuna Field	Ardjuna Field	Ardjuna Field	Cyrus field
Owner(s)/ Operator(s)	Cities Service	Union Oil	Pertamina	Union Oil	Atlantic Richfield	Atlantic Richfield	Atlantic Richfield	IPAC
Designer	SBM	McDermott	IMODCO	SBM	SBM	SBM	SBM	SBM
Tanker Size	35,000	70,000	100,000	250,000	35,000	150,000	150,000	130,000
Hose No. x Size (Inches)	2x8-in. underbuoy	2x20-in. underbuoy	2x12-in.	2x20-in.+ 1x16-in.	Flexpipe	3x16 in	2x16 in	2x16-in. floating
Year Installed	1975	1975	1970	1971	1976	1975	1975	1970
No. Moorings/ Type	SBS 350,000 bbl capacity	CALM	CALM	CALM	SBS for LPG	CALM	CALM	Storage Vessel Pazargad
Wind, % of Total								
0-1 knot	5	5	5	5	5	5	5	5
1-3 knots	12	12	12	12	12	12	12	11
4-10 knots	54	54	54	54	54	54	54	38
11-21 knots	26	26	26	26	26	26	26	26
22-33 knots	3	3	3	3	3	3	3	15
over 33 knots	0	0	0	0	0	0	0	5
Wave % of Total								
0-1 Ft.	17	17	17	17	17	17	17	32
1-3 Ft.	63	63	63	63	63	63	63	48
3-8 Ft.	19	19	19	19	19	19	19	14
over 8 Ft.	1	1	1	1	1	1	1	6
Current, Knots	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6
Tidal Variation	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT	10.4 FT
Low Water Depth	180 FT	NA	79 FT	120 FT	140 FT	138 FT	139 FT	142 FT
Comments								

Country	Iran	Israel	Italy	Italy	Italy	Italy	Italy	Italy
Location	Iman Hassan	Ashkelon	Fiumicino	Ravenna	Fiumicino	Genoa	Ancona	Ravenna
Owner(s)/ Operator(s)	SIRIP/ AGIP	Eilat-Ashkelon Pipeline	Purfina	Sarom	Roffineria di Roma	Port Authority	A.P.I.	Sarom
Designer	IMODCO		IMODCO	IMODCO	Dalmine	CIDINIO	CIDINIO	CIDINIO
Tanker Size	150,000	65,000	65,000	75,000	100,000	500,000	75,000	100,000
Hose No. x Size (Inches)	1x16-in.	2x20-in.	2x12-in.	2x10-in.	1x16-in.	2x20 in + 2x12 in	1 x 12 in	1x16 in
Year Installed	1970	1970	1962	1961	1974	1972	1974	1973
No. Moorings/ Type	CALM	CALM	CALM	Now Used As Part of Multi-Buoy Berth	Fixed Tower	Fixed Mooring Tower	Fixed Tower	CALM
Wind, % of Total								
0-1 knot	5	7	7	7	7	7	7	7
1-3 knots	11	14	14	14	14	14	14	14
4-10 knots	38	46	46	46	46	46	46	46
11-21 knots	26	21	21	21	21	21	21	21
22-33 knots	15	9	9	9	9	9	9	9
over 33 knots	5	3	3	3	3	3	3	3
Wave % of Total								
0-1 Ft.	32	10	10	10	10	10	10	10
1-3 Ft.	48	53	53	53	53	53	53	53
3-8 Ft.	14	30	30	30	30	30	30	30
over 8 Ft.	6	7	7	7	7	7	7	7
Current, Knots	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Tidal Variation	10.4 FT	3 FT	3 FT	3 FT	3 FT	3 FT	3 FT	3 FT
Low Water Depth	82 FT	NA	46 FT	48 FT	60 FT	NA	NA	80 FT
Comments				Out of Service				

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Country	Italy	Italy	Italy	Italy	Japan	Japan	Japan	Japan
Location	Ravenna	Fiumicino	Taranto	Porto Torres	Niigata	Yokkaichi	Yokkaichi	Oita
Owner(s)/ Operator(s)	Sarom	Roffin-eria di Roma	Shell	Sardoil	Shell	Showa Yokkaichi (Shell)	Showa Yokkaichi (Shell)	Kyushu Oil
Designer	IMODCO	Dalmine	SBM	SBM	SBM	Mitsub-ishi	Mitsub-ishi	IMODCO
Tanker Size	75,000	100,000	300,000	255,000	65,000	170,000	230,000	100,000
Hose No. x Size (Inches)	2x10-in.	1x16-in.	2x20-in.	2x20-in.	1x20-in	2x16-in.	2x12-in.	2x12-in
Year Installed	1961	1974	1969	1970	1961	1964	1964	1963
No. Moorings/ Type	Now Used As Part Of Multi Buoy Berth	Fixed Tower	CALM	CALM	CALM	CALM	CALM	CALM
Wind, % of Total								
0-1 knot	7	7	7	7	5	5	5	5
1-3 knots	14	14	14	14	10	10	10	10
4-10 knots	46	46	46	46	48	48	48	48
11-21 knots	21	21	21	21	33	33	33	33
22-33 knots	9	9	9	9	3	3	3	3
over 33 knots	3	3	3	3	1	1	1	1
Wave % of Total								
0-1 Ft.	10	10	10	10	8	8	8	8
1-3 Ft.	53	53	53	53	54	54	54	54
3-8 Ft.	30	30	30	30	33	33	33	33
over 8 Ft.	7	7	7	7	5	5	5	5
Current, Knots	0.4	0.4	0.4	0.4	2.0	2.0	2.0	2.0
Tidal Variation	3 FT	3 FT	3 FT	3 FT	7 FT	7 FT	7 FT	7 FT
Low Water Depth	48 FT	60 FT	NA	99 FT	NA	NA	NA	117 FT
Comments	Out of Service							Mooring trans. to St. John-New Bruns. Canada

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Country	Japan	Japan	Japan	Japan	Japan	Japan	Japan	Japan
Location	Chiba	Koshiba	Yokkaichi	Hakozaki	Kawasaki	Hakodate	Toyama	Yokohama
Owner(s)/ Operator(s)	Maruzen Oil	U.S.Navy	Daikyo Oil	U.S.Navy	Showa-Mitsubishi Oil	Asia Oil	Nihonkai	Asia Oil
Designer	IMODCO	IMODCO	Mitsubishi	IMODCO	Mitsubishi	IMODCO	IMODCO	Mitsubishi
Tanker Size	120,000	100,000	200,000	100,000	264,000	73,000	150,000	200,000
Hose No. x Size (Inches)	3x12-in.	2x12-in.	2x20-in.	2x16-in.+ 2x12-in.	2x20-in.	1x16-in.	2x16-in.	2x20-in.
Year Installed	1965	1967	1968	1968	1968	1968	1969	1969
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	CALM	CALM	CALM
Wind, % of Total								
0-1 knot	5	5	5	5	5	5	5	5
1-3 knots	10	10	10	10	10	10	10	10
4-10 knots	48	48	48	48	48	48	48	48
11-21 knots	33	33	33	33	33	33	33	33
22-33 knots	3	3	3	3	3	3	3	3
over 33 knots	1	1	1	1	1	1	1	1
Wave % of Total								
0-1 Ft.	8	8	8	8	8	8	8	8
1-3 Ft.	54	54	54	54	54	54	54	54
3-8 Ft.	33	33	33	33	33	33	33	33
over 8 Ft.	5	5	5	5	5	5	5	5
Current, Knots	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Tidal Variation	7 FT	7 FT	7 FT	7 FT	7 FT	7 FT	7 FT	7 FT
Low Water Depth	57 FT	65 FT	NA	60 FT	NA	49 FT	89 FT	NA
Comments								

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Country	Japan	Japan	Japan (Okinawa)	Japan (Okinawa)	Japan	Japan (Okinawa)	Korea	Korea
Location	Atsumi	Himeji	Nakagusu-ku Bay	Tengan	Ube ,	Nakagusu-ku Bay	Ulsan	Ulsan
Owner(s)/ Operator(s)	Chubu Electric	Idemitsu Oil	Toyo Oil, Caltex	U.S. Army	Seibu Oil	Nansei Sekiyu	Korea Oil	Korea Oil
Designer	Mitsubishi	IMODCO	IMODCO	IMODCO	Mitsubishi	Esso, van Houten	IMODCO	IMODCO
Tanker Size	200,000	250,000	100,000	55,000	200,000	255,000	75,000	200,000
Hose No. x Size (Inches)	2x20-in.	2x20-in.	2x16-in.	2x12-in.	2x20-in.	2x24-in.	2x12-in.+ 2x8-in.+	2x16-in+ 1x12-in.
Year Installed	1970	1970	1970	1970	1970	1971	1966	1968
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	SALM	CALM	CALM
Wind, % of Total								
0-1 knot	5	5	5	5	5	5	2	2
1-3 knots	10	10	10	10	10	10	4	4
4-10 knots	48	48	48	48	48	48	37	37
11-21 knots	33	33	33	33	33	33	42	42
22-33 knots	3	3	3	3	3	3	13	13
over 33 knots	1	1	1	1	1	1	2	2
Wave % of Total								
0-1 Ft.	8	8	8	8	8	8	11	11
1-3 Ft.	54	54	54	54	54	54	61	61
3-8 Ft.	33	33	33	33	33	33	22	22
over 8 Ft.	5	5	5	5	5	5	6	6
Current, Knots	2.0	2.0	2.0	2.0	2.0	2.0	0.8	0.8
Tidal Variation	7 FT	7 FT	7 FT	7 FT	7 FT	7 FT	31 FT	31 FT
Low Water Depth	NA	79 FT	85 FT	70 FT	NA	NA	65 FT	88 FT
Comments								

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Country	Korea	Korea	Kuwait	Kuwait	Libya	Libya	Libya	Libya
Location	Yosu	Pohang	Ras Al Khafji	Ras Al Khafji	Brega	Es Sider	Zuetina	Brega
Owner(s)/ Operator(s)	Honam Refining Caltex	U.S. Army	Arabian Oil	Arabian Oil	Esso	Oasis Oil	Occidental	Esso
Designer	IMODCO	NA	McDermott	McDermott	Esso, F.R.Harris	SBM	SBM	Esso,Van Houten
Tanker Size	100,000	NA	150,000	250,000	100,000	100,000	100,000	300,000
Hose No. x Size (Inches)	2x16-in.	NA	1x16-in.+ 1x12-in.	1x24-in.+ 1x10-in.	loading arm	3x16-in.	1x24-in.	1x24-in.
Year Installed	1968	1974	1967	1972	1962	1965	1968	1969
No. Moorings/ Type	CALM	CALM	CALM	CALM	Fixed mooring tower - underwater loading arm	CALM	CALM	SALM
Wind, % of Total								
0-1 knot	2	2	5	5	7	7	7	7
1-3 knots	4	4	11	11	14	14	14	14
4-10 knots	37	37	38	38	46	46	46	46
11-21 knots	42	42	26	26	21	21	21	21
22-33 knots	13	13	15	15	9	9	9	9
over 33 knots	2	2	5	5	3	3	3	3
Wave % of Total								
0-1 Ft.	11	11	32	32	10	10	10	10
1-3 Ft.	61	61	48	48	53	53	53	53
3-8 Ft.	22	22	14	14	30	30	30	30
over 8 Ft.	6	6	6	6	7	7	7	7
Current, Knots	0.8	0.8	0.6	0.6	0.4	0.4	0.4	0.4
Tidal Variation	31	31	10.4 FT	10.4 FT	3 FT	3 FT	3 FT	3 FT
Low Water Depth	112 FT	NA	NA	NA	NA	NA	117 FT	140 FT
Comments						Out of Service		

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Country	Libya	Libya	Libya	Libya	Libya	Libya	Libya	Libya
Location	Zuetina	Zuetina	Es Sider	Ras Lanuf	Azzawiya	Azzawiya	Azzawiya	Azzawiya
Owner(s)/ Operator(s)	Occiden-tal	Occiden-tal	Oasis Oil	Mobil	Libyan Nat.Oil Co.	Libyan Nat. Oil Co.	Libyan Nat. Oil Co.	Libyan Nat. Oil Co.
Designer	SBM	SBM	SBM	SBM	Woodfield	Woodfield	SBM	SBM
Tanker Size	150,000	150,000	255,000	300,000	100,000	30,000	140,000	100,000
Hose No. x Size (Inches)	1x24-in.	1x24-in.	2x20-in.	2x24-in.	2x16-in.	1x8-in.+ 1x10-in.	2x20-in.	2x20-in.
Year Installed	1968	1968	1969	1969	1974	1974	1977	1977
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	CALM	SALM	SALM
Wind, % of Total								
0-1 knot	7	7	7	7	7	7	7	7
1-3 knots	14	14	14	14	14	14	14	14
4-10 knots	46	46	46	46	46	46	46	46
11-21 knots	21	21	21	21	21	21	21	21
22-33 knots	9	9	9	9	9	9	9	9
over 33 knots	3	3	3	3	3	3	3	3
Wave % of Total								
0-1 Ft.	10	10	10	10	10	10	10	10
1-3 Ft.	53	53	53	53	53	53	53	53
3-8 Ft.	30	30	30	30	30	30	30	30
over 8 Ft.	7	7	7	7	7	7	7	7
Current, Knots	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Tidal Variation	3 FT	3 FT	3 FT	3 FT	3 FT	3 FT	3 FT	3 FT
Low Water Depth	107 FT	110 FT	NA	96 FT	NA	NA	98 FT	98 FT
Comments					Out of Service	Out of Service		

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Country	Malaysia	Malaysia	Malaysia	Malaysia	Malaysia	Malaysia	Mexico	Mexico
Location	Pulai Field	Tembongo Field	Miri (Sarawak)	Port Dickson	Miri	South China Sea	Tuxpan	Tuxpan
Owner(s)/ Operator(s)	Exxon	Exxon	Shell	Shell/Esso	Shell	Pulai field Exxon	Pemex	Pemex
Designer	SBM	SOFEC	SBM	SBM	SBM	SBM	IMODCO	IMODCO
Tanker Size	190,000	94,000	45,000	90,000	65,000	190,000	60,000	60,000
Hose No. x Size (Inches)	1x12 in	1x10 in	2x8-in.+ 1x6-in.	2x16-in.	2x12-in.	1x12-in.	2x16-in.	3x16-in.+ 1x10-in.
Year Installed	1976	1974	1959	1963	1964	1975	1973	1974
No. Moorings/ Type	SALM Permanent Mooring of storage tanker of 190,000 DWT	SALM	2/ CALM	CALM	2/ CALM	SALM	CALM	CALM
Wind, % of Total								
0-1 knot	5	5	5	5	5	5	4	4
1-3 knots	12	12	12	12	12	12	8	8
4-10 knots	54	54	54	54	54	54	47	47
11-21 knots	26	26	26	26	26	26	30	30
22-33 knots	3	3	3	3	3	3	10	10
over 33 knots	0	0	0	0	0	0	1	1
Wave % of Total								
0-1 Ft.	17	17	17	17	17	17	6	6
1-3 Ft.	63	63	63	63	63	63	58	58
3-8 Ft.	19	19	19	19	19	19	34	34
over 8 Ft.	1	1	1	1	1	1	2	2
Current, Knots	0.7	0.7	0.7	0.7	0.7	0.7	1.5	1.5
Tidal Variation	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT	15.3 FT	2.1 FT	2.1 FT
Low Water Depth	245 FT	296 FT	NA	NA	NA	245 FT	67 FT	75 FT
Comments								

Country	Mexico	Mexico	Morocco	New Zealand	New Zealand	Nigeria	Nigeria	Nigeria
Location	Salina Cruz	Rosarito Beach	Mohamme-dia	Waipipi	Taharoa	Apapa	Escravos	Forcados
Owner(s)/ Operator(s)	Pemex	Pemex	RAPC	Marcona	NZ Steel	Nidogas	Gulf	Shell-BP
Designer	IMODCO	IMODCO	IMODCO	IMODCO	IMODCO	IMODCO	IMODCO	SBM
Tanker Size	60,000	60,000	100,000	75,000	70,000	4,000	100,000	240,000
Hose No. x Size (Inches)	3x16-in.+ 1x12-in.	1x16-in. 1x20-in.	1x20-in.+ 2x8-in.	2x12-in.	1x12-in.	1x4-in. (LP-gas)+	3x16-in.	1x24-in.
Year Installed	1975	1975	1970	1971	1972	1967	1968	1968
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	CALM	CALM	CALM
Wind, % of Total			NA					
0-1 knot	4	4		1	1	2	2	2
1-3 knots	8	8		2	2	8	8	8
4-10 knots	47	47		22	22	61	61	61
11-21 knots	30	30		45	45	23	23	23
22-33 knots	10	10		23	23	5	5	5
over 33 knots	1	1		7	7	1	1	1
Wave % of Total			NA					
0-1 Ft.	6	6		5	5	4	4	4
1-3 Ft.	58	58		46	46	64	64	64
3-8 Ft.	34	34		41	41	29	29	29
over 8 Ft.	2	2		8	8	3	3	3
Current, Knots	1.5	1.5	NA	0.6	0.6	0.8	0.8	0.8
Tidal Variation	2.1 FT	2.1 FT	NA	2.8 FT	2.8 FT	7 FT	7 FT	7 FT
Low Water Depth	75 FT	77 FT	72 FT	64 FT	74 FT	13 FT	70 FT	NA
Comments				Iron Ore Slurry Facility	Bulk Ore Slurry Transfer	LPG Gas Facility		

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Country	Nigeria	Nigeria	Nigeria	Nigeria	Nigeria	Nigeria	Nigeria	Nigeria
Location	Forcados	Escravos	Brass River	Bonny	Bonny	North Apoi field	North Apoi field	Brass Zone
Owner(s)/ Operator(s)	Shell	Gulf	AGIP	Shell B.P.	Shell B.P.	Texaco	Texaco	NAOC (AGIP)
Designer	SBM	SBM	IMODCO	SBM	SBM	SBM	SBM	IMODCO
Tanker Size	375,000	326,000	250,000	375,000	375,000	50,000	250,000	250,000
Hose No. x Size (Inches)	2x24-in.	2x24-in.	1x20-in.	2x24-in.	2x24-in.	1x20-in.	2x20-in.+ 1x12-in.	2x20-in.
Year Installed	1971	1970	1972	1971	1971	1974	1974	1975
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	SPM Perm. Stor. Tanker of 50,000 dwt.	CALM	CALM
Wind, % of Total								
0-1 knot	2	2	2	2	2	2	2	2
1-3 knots	8	8	8	8	8	8	8	8
4-10 knots	61	61	61	61	61	61	61	61
11-21 knots	23	23	23	23	23	23	23	23
22-33 knots	5	5	5	5	5	5	5	5
over 33 knots	1	1	1	1	1	1	1	1
Wave % of Total								
0-1 Ft.	4	4	4	4	4	4	4	4
1-3 Ft.	64	64	64	64	64	64	64	64
3-8 Ft.	29	29	29	29	29	29	29	29
over 8 Ft.	3	3	3	3	3	3	3	3
Current, Knots	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Tidal Variation	7 FT	7 FT	7 FT	7 FT	7 FT	7 FT	7 FT	7 FT
Low Water Depth	NA	103 FT	96 FT	NA	NA	87 FT	87 FT	95 FT
Comments								

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Country	Nigeria	Nigeria	Norway	Norway	Oman	Oman	Oman	Oman
Location	Forcados	Qua Iboe	(North Sea)	(North Sea)	Mina Al Fahal	Saih el Malih	Saih el Malih	Mina Al Fahal
Owner(s)/ Operator(s)	Shell-BP	Mobil	Phillips	Phillips	Shell	Shell	Shell	Shell
Designer	SBM	IMODCO	SBM	SBM	SBM	SBM	SBM	SBM
Tanker Size	240,000	255,000	150,000	60,000	165,000	165,000	165,000	500,000
Hose No. x Size (Inches)	1x20-in.	2x24-in.	1x6-in.	1x6-in.	2x20-in. +2x8-in.	2x16-in.+ 2x8-in.	2x16-in.+ 2x8-in.	2x20-in.+ 1x12-in.
Year Installed	1968	1971	1970	1970	1963	1966	1966	1973
No. Moorings/ Type	CALM	CALM	CALM	CALM	2/ CALM	CALM	CALM	CALM
Wind, % of Total								
0-1 knot	2	2	2	2	5	5	5	5
1-3 knots	8	8	6	6	11	11	11	11
4-10 knots	61	61	35	35	38	38	38	38
11-21 knots	23	23	35	35	26	26	26	26
22-33 knots	5	5	16	16	15	15	15	15
over 33 knots	1	1	6	6	5	5	5	5
Wave % of Total								
0-1 Ft.	4	4	5	5	32	32	32	32
1-3 Ft.	64	64	54	54	48	48	48	48
3-8 Ft.	29	29	32	32	14	14	14	14
over 8 Ft.	3	3	9	9	6	6	6	6
Current, Knots	0.8	0.8	0.5	0.5	0.6	0.6	0.6	0.6
Tidal Variation	7 FT	7 FT/	7.2 FT	7.2 FT	10.4 FT	10.4 FT	10.4 FT	10.4 FT
Low Water Depth	NA	90 FT	232 FT	NA	NA	NA	NA	NA
Comments								

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Country	Philippines	Qatar	Qatar	Qatar	Sarawak	Saudi Arabia	Saudi Arabia	Saudi Arabia
Location	Subic Bay	Halul	Halul	Umm Said	Bintulu	Zuluf	Zuluf	Ju'Aymah
Owner(s)/ Operator(s)	U.S. Navy	Shell	Shell	Qatar Petroleum	Shell	Aramco	Aramco	Aramco
Designer	IMODCO	SBM	McDermott	IMODCO	SBM	SBM	SBM	McDermott
Tanker Size	108,000	200,000	300,000	300,000	250,000	250,000	450,000	500,000
Hose No. x Size (Inches)	2x12-in.+ 1x10-in.	2x16-in.	2x24-in.+	2x24-in.	2x20-in.	2x24-in.+ 1x16-in.	2x24-in.	2x24-in.+ 1x12-in.
Year Installed	1967	1965	1972	1972	1975	1970	1970	1974
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	SBS 250,000 DWT	CALM	CALM
Wind, % of Total	NA							
0-1 knot		5	5	5	5	5	5	5
1-3 knots		11	11	11	12	11	11	11
4-10 knots		38	38	38	54	38	38	38
11-21 knots		26	26	26	26	26	26	26
22-33 knots		15	15	15	3	15	15	15
over 33 knots		5	5	5	0	5	5	5
Wave % of Total	NA							
0-1 Ft.		32	32	32	17	32	32	32
1-3 Ft.		48	48	48	63	48	48	48
3-8 Ft.		14	14	14	19	14	14	14
over 8 Ft.		6	6	6	1	6	6	6
Current, Knots	NA	0.6	0.6	0.6	0.7	0.6	0.6	0.6
Tidal Variation	NA	10.4 FT	10.4 FT	10.4 FT	15.3 FT	10.4 FT	10.4 FT	10.4 FT
Low Water Depth	85 FT	NA	NA	66 FT	NA	116 FT	129 FT	110 FT
Comments	In use through Mid-1976					In use through mid-1976	In use through mid-1976	

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Country	Saudi Arabia	Saudi Arabia	Saudi Arabia	Saudi Arabia	Singapore	Singapore	South Africa	South Africa
Location	Ju'Aymah	Ju'Aymah	Ju'aymah	Ju'aymah	Singapore	Singapore	Durban	Durban
Owner(s)/ Operator(s)	Aramco	Aramco	ARAMCO	ARAMCO	Esso	Shell	Shell	Shell
Designer	McDermott	McDermott	SOFEC	SOFEC	IMODCO	McDermott	SBM	SBM
Tanker Size	500,000	500,000	750,000	500,000	250,000	300,000	200,000	250,000
Hose No. x Size (Inches)	2x24-in+ 1x12-in.	2x24-in.+ 1x12-in.	2x24 in 1x12 in	2x24 in 1x12 in	2x24-in.	2x24-in.	2x24-in.	2x20-in.
Year Installed	1974	1974	1976	1976	1970	1974	1969	1975
No. Moorings/ Type	CALM	CALM	SALM	SALM	SALM	CALM	CALM	CALM
Wind, % of Total							NA	NA
0-1 knot	5	5	5	5	5	5		
1-3 knots	11	11	11	11	12	12		
4-10 knots	38	38	38	38	54	54		
11-21 knots	26	26	26	26	26	26		
22-33 knots	15	15	15	15	3	3		
over 33 knots	5	5	5	5	0	0		
Wave % of Total							NA	NA
0-1 Ft.	32	32	32	32	17	17		
1-3 Ft.	48	48	48	48	63	63		
3-8 Ft.	14	14	14	14	19	19		
over 8 Ft.	6	6	6	6	1	1		
Current, Knots	0.6	0.6	0.6	0.6	0.7	0.7	NA	NA
Tidal Variation	10.4 FT	10.4 FT	10.4 FT	10.4 FT	15.3 FT	15.3 FT	NA	NA
Low Water Depth	110 FT	110 FT	129 FT	117 FT	88 FT	NA	NA	NA
Comments					1		Replaced in 1975	

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Country	South Africa	S.Vietnam	Spain	Spain	Spain	Spain	Spain	Spanish Guinea
Location	Durban	Tan My	Algeciras Bay	Algeciras	Huelva	Amposta	Tarragona	Bata
Owner(s)/ Operator(s)	Shell	U.S. Navy	CEPSA	CEPSA	Gulf	Shell	Entasa	CEPSA
Designer	SBM	McDermott	Brown and Vosper	Woodfield	SBM	SBM	SBM	IMODCO
Tanker Size	250,000	20,000	500,000	410,000	100,000	60,000	325,000	20,000
Hose No. x Size (Inches)	2x20 in	2x8 in	2x20 in 1x12 in	2x24 in + 1x12 in	2x16-in.	2x10-in.	1x20-in.	2x6-in. 2x8-in.
Year Installed	1975	1969	1976	1975	1967	1971	1973	1963
No. Moorings/ Type	CALM	CALM	CALM	Four Taut Anchor Legs	CALM	SBS 60,000 DWT	CALM	CALM
Wind, % of Total	NA	NA			NA	NA	NA	
0-1 knot			7	7				1
1-3 knots			14	14				5
4-10 knots			46	46				41
11-21 knots			21	21				35
22-33 knots			9	9				17
over 33 knots			3	3				1
Wave % of Total	NA	NA			NA	NA	NA	
0-1 Ft.			10	10				2
1-3 Ft.			53	53				49
3-8 Ft.			30	30				45
over 8 Ft.			7	7				4
Current, Knots	NA	NA	0.4	0.4	NA	NA	NA	0.7
Tidal Variation	NA	NA	3 FT	3 FT	NA	NA	NA	1.5 FT
Low Water Depth	200 FT	NA	NA	NA	NA	NA	131 FT	25 FT
Comments		Out of Service						

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Country	Spanish Sahara	Sweden	Taiwan	Taiwan	Taiwan	Taiwan	Taiwan	Taiwan
Location	El Aajun	Dalaro	Tai-Chung	Tai-Chung	Kaoshsi-ung	Kaoshsi-ung	Northern Terminal	Chu-Wei
Owner(s)/ Operator(s)	CEPSA	Swedish Navy	USAF	USAF	Chinese Pet.	CPC	CPC	Chinese Pet Corp.
Designer	IMODCO	IMODCO	IMODCO	IMODCO	IMODCO	SBM	SBM	IMODCO
Tanker Size	5,000	3,000	50,000	50,000	100,000	250,000	250,000	250,000
Hose No. x Size (Inches)	1x8-in.	1x4-in.	1x12-in.	1x12-in.	2x16-in.+ 1x10-in.	2x20-in.	2x20-in.	2x20 in
Year Installed	1961	1959	1967	1968	1968	1971	1972	1975
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	CALM	CALM	2/SALM
Wind, % of Total	NA							
0-1 knot		2	2	2	2	2	2	2
1-3 knots		6	4	4	4	4	4	4
4-10 knots		35	37	37	37	37	37	37
11-21 knots		35	42	42	42	42	42	42
22-33 knots		16	13	13	13	13	13	13
over 33 knots		6	2	2	2	2	2	2
Wave % of Total	NA							
0-1 Ft.		5	11	11	11	11	11	11
1-3 Ft.		54	61	61	61	61	61	61
3-8 Ft.		32	22	22	22	22	22	22
over 8 Ft.		9	6	6	6	6	6	6
Current, Knots	NA	0.5	0.8	0.8	0.8	0.8	0.8	0.8
Tidal Variation	NA	7.2 FT	31 FT	7.2 FT	7.2 FT	7.2 FT	7.2 FT	31 FT
Low Water Depth	27.5 FT	98 FT	NA	NA	68 FT	31 FT	NA	120 FT
Comments	Out of Service	Out of Service	Out of Service	Out of Service				

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Country	Taiwan	Tanzania	Trinidad	Trinidad	Trinidad	Tunisia	Tunisia	Trucial States
Location	Chu Wei	Dar Es Salaam	Galeota Point	Point-a-Pierre	Galeora Point	Gulf of Gabes	Ashtart	Sharjah
Owner(s)/ Operator(s)	Chinese Pet.	E.A. Port Auth.	Amoco	Texaco	Amoco Trinidad Oil	Acquitaine Quitaine	Acquitaine	Crescent
Designer	SBM	SBM	SBM	IMODCO	IMODCO	SBM Single buoy storage system cap. 524,000	SBM	SBM
Tanker Size	250,000	100,000	250,000	265,000	250,000		100,000	350,000
Hose No. x Size (Inches)	2x20-in.	2x20-in.	2x20-in.	2x24-in+ 1x12-in.	2x20-in.+	2x8-in.	1x20-in. floating	1x20-in.
Year Installed	1975	1971	1971	1973	1976	1972	1974	1973
No. Moorings/ Type	CALM	CALM	CALM	CALM	CALM	SBS 524,000 bbl.	CALM	CALM
Wind, % of Total		NA	7	7	7	7	7	NA
0-1 knot	2		14	14	14	14	14	
1-3 knots	4		46	46	46	46	46	
4-10 knots	37		21	21	21	21	21	
11-21 knots	42		9	9	9	9	9	
22-33 knots	13		3	3	3	3	3	
over 33 knots	2							
Wave % of Total		NA						NA
0-1 Ft.	11		10	10	10	10	10	
1-3 Ft.	61		53	53	53	53	53	
3-8 Ft.	22		30	30	30	30	30	
over 8 Ft.	6		7	7	7	7	7	
Current, Knots	0.8	NA	0.4	0.4	0.4	0.4	0.4	NA
Tidal Variation	31 FT	NA	3 FT	3 FT	3 FT	3 FT	3 FT	NA
Low Water Depth	115 FT	78 FT	95 FT	78 FT	95 FT	220 FT	220 FT	160 FT
Comments								

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Country	U.A.E.*	United Kingdom	United Kingdom	United Kingdom	United Kingdom	United Kingdom	United Kingdom	United Kingdom
Location	Dubai	(N.Sea) Beryl Field	(N.Sea) Orkney Island	(N.Sea) Orkney Island	(N.Sea) Brent Field	(N.Sea) Montrose Field	(N.Sea) Montrose Field	Humber River
Owner(s)/ Operator(s)	Conti-nental	Mobil	Occidental	Occidental	Shell/ Esso	AMOCO	AMOCO	Conoco
Designer	SBM	EMH/CFEM	Microperi	Microperi	Shell/SBM IHC	SBM	SBM	SBM
Tanker Size	150,000	80,000	250,000	250,000	90,000	80,000	80,000	210,000
Hose No. x Size (Inches)	2x16 in	2x16 in	1x24 in 1x20 in	1x24 in 1x20 in	2x8 in 2.12 in	1x10 in	1x10 in	1x24-in.
Year Installed	1969	1976	1976	1976	1975	1975	1975	1970
No. Moorings/ Type	CALM	SPM Tower	SPM Tower	SPM Tower	CALM	CALM	CALM	CALM
Wind, % of Total								
0-1 knot	5	2	2	2	2	2	2	NA
1-3 knots	11	6	6	6	6	6	6	
4-10 knots	38	35	35	35	35	35	35	
11-21 knots	26	35	35	35	36	35	35	
22-33 knots	15	16	16	16	16	16	16	
over 33 knots	5	6	6	6	6	6	6	
Wave % of Total								
0-1 Ft.	32	5	5	5	5	5	5	NA
1-3 Ft.	48	54	54	54	54	54	54	
3-8 Ft.	14	32	32	32	32	32	32	
over 8 Ft.	6	9	9	9	9	9	9	
Current, Knots	0.6	0.5	0.5	0.5	0.5	0.5	0.5	NA
Tidal Variation	10.4 FT	7.2 FT	7.2 FT	7.2 FT	7.2 FT	7.2 FT	7.2 FT	NA
Low Water Depth	132 FT	392 FT	100 FT	100 FT	425 FT	300 FT	300 FT	74 FT
Comments	*United Arab Emirates							

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Country Location Owner(s)/ Operator(s)	United Kingdom (N. Sea) Auk field Shell/ Esso	United Kingdom Anglesey Shell UK	United Kingdom (N.Sea)Argyll field Hamilton	United Kingdom (N.Sea) Montrose field Amoco	United Kingdom (N.Sea) Montrose field Amoco	United Kingdom (N.Sea) Thistle field Burmah	United States Santa Ynez, Calif. Exxon	Uruguay Jose Ignacio Ancap
Designer	SBM/Shell	SBM	SBM	SBM	SBM	SBM	IMODCO	SBM
Tanker Size	50,000	540,000	100,000	50,000	50,000	80,000	75,000	150,000
Hose No. x Size (Inches)	2x10-in.	2x24-in.+ 1x16-in.	1x16-in.	1x10-in.	1x10-in.	2x16-in.	1x20-in.	2x20 in. underbuoy +1x24-in. floating
Year Installed	1974	1976	1974	1974	1974	1975	1977	1975
No. Moorings/ Type	ELSBM	Flex pipe for under buoy use lieu of hose	CALM	CALM	CALM	CALM	SALM	CALM
Wind, % of Total								
0-1 knot	2	2	2	2	2	2	NA	3
1-3 knots	6	6	6	6	6	6		7
4-10 knots	35	35	35	35	35	35		33
11-21 knots	35	35	35	35	35	35		35
22-33 knots	16	16	16	16	16	16		16
over 33 knots	6	6	6	6	6	6		6
Wave % of Total								
0-1 Ft.	5	5	5	5	5	5	NA	9
1-3 Ft.	54	54	54	54	54	54		49
3-8 Ft.	32	32	32	32	32	32		40
over 8 Ft.	9	9	9	9	9	9		2
Current, Knots	0.5	0.5	0.5	0.5	0.5	0.5	NA	0.7
Tidal Variation	7.2 FT	7.2 FT	7.2 FT	7.2 FT	7.2 FT	7.2 FT	NA	12.8 FT
Low Water Depth	280 FT	NA	246 FT	NA	NA	NA	105 FT	NA
Comments								

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Country	United Kingdom	Uruguay	Venezuela	Zaire	Zaire			
Location	(N.Sea) Thistle Field	Punta L'esta	Moron	Zaire	Zaire			
Owner(s)/ Operator(s)	Burmah	ANCAP	CVP	Gulf Oil	Gulf Zaire			
Designer	DBV/SBM	SBM	SBM	IMODCO	IMODCO			
Tanker Size	80,000	150,000	100,000	100,000	72,000			
Hose No. x Size (Inches)	2x16 in	NA	2x16-in.	1x20-in.	2x16-in.			
Year Installed	1976	NA	1968	1974	1975			
No. Moorings/ Type	SALM	CALM	CALM	CALM	CALM			
Wind, % of Total								
0-1 knot	2	3	1	2	2			
1-3 knots	6	7	5	8	8			
4-10 knots	35	33	41	61	61			
11-21 knots	35	35	35	23	23			
22-33 knots	16	16	17	5	5			
over 33 knots	6	6	1	1	1			
Wave % of Total								
0-1 Ft.	5	9	2	4	4			
1-3 Ft.	54	49	49	64	64			
3-8 Ft.	32	40	45	29	29			
over 8 Ft.	9	2	4	3	3			
Current, Knots	0.5	0.7	0.7	0.8	0.8			
Tidal Variation	7.2 FT	12.8 FT	1.5 FT	7 FT	7 FT			
Low Water Depth	530 FT	64 FT	63 FT	71 FT	79 FT			
Comments								

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Appendix B

FAILURE MODES AND EFFECTS ANALYSIS

Appendix B

FAILURE MODES AND EFFECTS ANALYSIS

Component	Failure Mode	Effect on System	Redundant Component or Mitigating Factors
1. SHIPBOARD COMPONENTS			
A. Topside Lines	Crack, weld failure	Leak onto deck, sea	Coaming
B. Manifold	Weld failure	Leak onto deck	Tail hose valve, coaming
C. Expansion Joint			
D. Isolation Valve	Sticks open	Leak onto deck	Tail hose valve
	Failure to seat		Drip pan, coaming
	Seals and gasket failure		
	Rupture		
E. Gasket	Deterioration	Shorten service life	Drip pan, coaming
	Rupture	Leak onto deck	
F. Flange	Weld failure	Leak onto deck	Drip pan, coaming
	Crack		
2. HOSE COMPONENTS			
A. Blind Flange	Loose bolts,gasket failure	Leaks	Butterfly isolation valve
B. Tail hose butter-fly valve	Sticks open	Leakage onto deck	Ship's isolation valve, Drip pan, coaming
	Fails to seat securely Stem seal failure	Leakage of hose contents if not connected	Blind flange
C. Rubber Lining	Blister	Shortens service life	
	Crack through wall	Leakage	
	Crack along liner/nipple Interface	Leakage	Bond of liner to nipple

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Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component or Mitigating Factors
D. Breaker	Broken filaments Slippage relative to liner Insufficient rubber	Internal abrasion Lump on liner-increased wear; Rubbing on wires	Counterwound reinforcing Wires
E. Reinforcing Plies	Wire Fracture Wire Slippage	Shorten service life Leakage Lump on liner	Multiple plies Multiple binding wires
F. Helical Reinforcing Wire	Kink Stretch Breakage	Hose Blockage Reduced Flow Area Leakage, fracture Penetration of Inner or Outer Liners, Hose Fracture, Hydrocarbon Leakage	 Reinforcing Plies Reinforcing Plies
G. Filler Rubber	Air Voids Rubber Disintegration	Increased Internal Motion in Hose	Inspection During Manufacture
H. Outer Cover-Floating Hose Only	Mechnical Cuts Abrasion Cracks	Potential Penetration to Hose Interior	
I. Flotation-Floating Hose Only	Loss of Buoyancy Through Age Mechanical Cuts Submersion	Hose Lays Deeper in Water Foam Exposed to Sea Water Collapse of Foam Material Due to pressure	Reserve Buoyancy Closed Cell Foam Specified

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Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component or Mitigating Factors
J. Nipple	Weld Defect Rupture	Hose Leaks	Inspection Design Thickness Specification
K. Retainer Rings	Weld Failure	Nipple Pull-Out Under Axial or Bending Load	3 Rings
L. Binding Wire	Wire Breakage	Nipple Pull-Out Under Load-Tension or Bending	3 Wrapping Locations
3. SALM BUOY COMPONENTS			
A. Hose Swivel	Seal Failure Sticks in Place	Leakage Binding and Tangling of Hoses	Multiple Seals
B. Fluid Chamber	Sticks in place Seal Failure Rupture	Binding, Strain on Hoses Leakage	Multiple Seals
C. Pipe Section	Weld Failure Abrasion	Leakage Increased Wear, Shortens Service Life	2 Parallel Sections
D. Underbuoy Riser Pipe	Crack Fatigue Failure	Leakage	

Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component or Mitigating Factors
E. Mooring Hawser	Stretch Break	Loss of Ship's Mooring Strain on Hoses	
F. Mooring Buoy	Loss of Buoyancy	Strain on Mooring Lines	
G. Anchor Chain	Break	Loss of Mooring and Strain on Hoses	
H. Anchor Chain Universal Joints	Bind Break Connection	Strain on Mooring Loss of Mooring	Multiple Universal Joints
I. Anchor Base	Settle or Shift	Strain on OTS, Potential Cause of Leak	
Anchor Piles	Loosen	Anchor Base Shifts	Multiple Piles
4. CALM BUOY COMPONENTS			
A. Overboard Piping	Weld Failure Corrosion Rupture	Leakage	Paint Inspection
B. Valve (Ref 2)	Seals and Gasket Failure Rupture	Leakage	Hose and PLEM Isolation Values

Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component or Mitigating Factors
C. Swivel	Seal Failure Rupture	Leakage	Multiple Seals
D. Rotating Deck	Bearing Failure	Binding/Tangling of Hoses	Multiple Bearing Wheels
E. Buoyancy Chamber	Puncture	Loss of Buoyancy	Multiple Chambers and Flotation Materials
F. Inner Buoy Valve (Ref 3)	Seal and Gasket Failure Rupture	Leakage	Hose and PLEM Isolation Valves
G. Underbuoy Hoses	See Hose Components #6-16		
H. Mooring Hawser	Stretch Break	Loss of Ship's Mooring Strain on Hoses	
I. Anchor Chains	Link Breaks Corrosion Abrasion	Excessive Monobuoy Movement, Strain on Hoses	Multiple Chains
J. Anchors or Stake Piles	Pulls Loose Breaks Corrosion	Excessive Monobuoy Movement, Strain on Hoses	Multiple Anchors

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Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component or Mitigating Factors
K. Pipeline End Manifold (PLEM)	Weld Failure Corrosion Rupture Movement	Leakage	Inspection During Fabrication and Installation Hose Isolation Valve
L. PLEM Isolation Valve	Failure to Close on Demand Seal and Gasket Leak Rupture	Leakage	Hose Isolation Valve
M. Check Valve	Failure to Open Rupture	Increased Pressure in PLEM Leakage	Measurement of Flow Rate, Pressures
N. Pipeline	Weld Failure Fatigue Failure Rupture	Leakage Leakage Leakage	Inspection During Operation Regulation of Flow Pressures
	Corrosion	Shortened Service Life	Design
O. Risers	Structural Collapse Due to Clamps Corrosion Fatigure Failure Rupture	Leakage	Inspection During Installation and Operation

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Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component or Mitigating Factors
5. PUMPING PLATFORM COMPONENTS			
A. Incoming Manifold Valves	Failure to Open/ Close on Demand Seal and Gasket Failure Stem Failure Rupture	Misdirected Oil Flow Leakage	Control Checks Visual Observation Manual Backup Flexible Routing Decking and Drains
B. Platform Piping	Weld Failure Crack Internal Corrosion	Leakage Shortened Service Life	Inspection During Fabrication and Operation Decking and Drains
C. In-Line Sampler Valve	Failure to Close on Demand Seal and Gasket Leak Rupture	Leakage	Visual Observation Decking and Drains
D. Strainer	Mesh Blocked Basket Rupture	Decreased Flow and Leakage Damage to Pumps	Flow Indicators Decking and Drains
E. Strainer Drain Valve	Failure to Close on Demand Seal and Gasket Leak Rupture	Leakage	Maintenance Procedures Visual Observation Decking and Drains
F. Air Eliminator	Float Switch Failure Container Rupture Vent Overflow	Overflow-Leakage Leakage	Maintenance Procedures Fabrication Inspection Decking and Drains

Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component or Mitigating Factors
G. Air Eliminator Drain Valve	Failure to Close on Demand Seal Leak Rupture	Leakage	Maintenance Procedures Decking and Drains
H. Pressure Relief Valves and Lines	Rupture Cracks Seal and Gasket Failure	Leakage	Decking and Drains
I. Pump Suction and Discharge Valves	Failure to Close/Open on Demand Seal Leak Rupture	Reduced Flow Leakage Reverse Flow to Air Eliminator	Isolation Valves and Operating Procedures Decking and Drains
J. Pumps	Casing Rupture Seal Failure Bearing Failure Sensor Failure Corrosion of Pump	Leakage Pump Runaway Shortened Service Life	Sensors Maintenance Procedures Multiple Pumps Decking and Drains
K. Pump Check Valves	Failure to Open Reverse Leak Rupture	Increased Pump Pressure Leakage	Maintenance Procedure Control system Decking and Drains
L. Pump Control Valve	Seal and Gasket Failure Failure to Respond Actuator Failure Rupture	Change in Flow Rates Pump Runaway Leakage	Control System Maintenance Procedure Decking and Drains

Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component Mitigating Factors
M. Meter Isolation Valves	Failure to Close on Demand Seal and Gasket Failure Rupture	Leakage	Control System Maintenance Procedures Decking and Drains
N. Flow Straightener	Rupture	Leakage	Decking and Drains
O. Turbine Flow Meter	Rupture Corrosion	Leakage	Maintenance Procedures Observation Decking and Drains
P. Post-Meter Check Valves	Failure to Open Reverse Leak Rupture Seal and Gasket Failure	Increased Line Pressure Leakage	Maintenance Procedures Control System Decking and Drains
Q. Prover Line Valves	Seal and Gasket Failure Failure to Open/Close on Demand Rupture	Decreased Flow Rate Increased Line Pressure Leakage	Maintenance Procedures Flexible Valve Arrangement Decking and Drains
R. Prover	Divertor Valve Leaks Line Rupture Seal and Gasket Failure	Inaccurate Readings Leakage	Calibration of Instrument Decking and Drains
S. Pig Launcher	Seal Leak Weld Failure Crack Rupture	Leakage	Launcher Isolation Valve Decking and Drains

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Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component Mitigating Factors
T. Launcher Isolation Valve	Failure to Close on Demand Seal and Gasket Failure Rupture	Leakage	Decking and Drains
U. Reclaimed Oil Tank	Weld Failure Crack Rupture	Leakage to Drain Leakage to Drain	Inspection During Installation and Operation Decking and Drains
V. Maintenance Oil Drain Tank	Weld Failure Crack Rupture Rupture	Leakage to Drain	Inspection During Installation and Operation Decking and Drains
W. Skimmer Tank	Weld Failure Crack Rupture	Leakage to Drain	Inspection During Installation and Operation Decking and Drains
X. Oily Water Sump	Weld Failure Crack Rupture	Leakage onto Water	Inspection During Installation and Operation
Y. Oil/Water Separator	Weld Failure Crack Rupture	Leakage	Inspection During Installation and Operation Decking and Drains

Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component Mitigating Factors
Z. Sea Sump	Weld Failure Crack Rupture Overflow	Possible Leakage into Water	Inspection During Installation and Operation
AA. Waste Disposal System Pumps (5)	Bearing Failure Seal Failure	Pump Damage	
	Casing Rupture	Leakage	
	Failure to Start on Demand		Emergency Overflow Line
	Failure to Continue Running	System Imbalance	Decking and Drains
BB. Pump Suction and Discharge Valves	Failure to Open/Close on Demand	Pump Damage	
	Seal Fails Rupture	Leakage	Maintenance Procedures
CC. Pump Check Valve	Failure to Open	Reduced Line Capacity	Discharge Valves
	Rupture	Leakage	Maintenance Procedures
DD. Waste Disposal System Valves	Failure to Open/Close on Demand Seal and Gasket Failures Rupture	Leakage	Maintenance Procedures Control System

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Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component Mitigating Factors
DD. Offshore Pipeline	Weld Failure Fatigue Failure Corrosion Coating Failure Rupture Internal Corrosion	Leakage Shortened Service Life	Inspection During Fabrication and Operation Design, Cathodic protection Control System Corrosion Inhibitors
6. BOOSTER PUMP STATION COMPONENTS			
A. Isolation Valve	Failure to Close on Demand Failure to Seal Stem Failure Rupture	Leakage	Maintenance Procedures
B. Station Valves	Seals and Gaskets Rupture	Leakage	Maintenance Dike
C. Pumps	Casing Crack or Rupture Seals and Gaskets Corrosion	Leakage	Control System Maintenance Dike
D. Piping	Crack Weld Failure	Leakage	Dike

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Appendix B (continued)

Component	Failure Mode	Effect on System	Redundant Component Mitigating Factors
7. STORAGE FACILITY COMPONENTS			
A. Scraper Receiver	Seal Leak Weld Failure Crack Rupture	Leakage	Collector Pan Maintenance Isolation Valves
B. Meter Run	See 5 L-O		Containment Dike
C. Prover	See 5 P-Q		Containment Dike
D. Receiving Manifold Valves	Failure to Open/Close on Demand Seal Failure Stem Failure Rupture	Misdirected Oil Flow Leakage	Control System Visual Observation Flexible Routing
E. Surge Relief System	Tank Rupture Weld Failure	Leakage	Inspection During Installation Dikes
F. Oily Water Separator	Pump Seal Failure Tank Rupture Valve Leakage	Leakage	Drains Dike

REFERENCES FOR FMEA

1. Briggs and Wolfe, Study of Large Bore Offshore Loading and Discharge Hose SWRI.

2. The Submarine Pipeline and Single Buoy Mooring, S.W. Small, Bechtel Corp.

3. K. B. MacKenzie and G. C.Lee, Design and Construction Aspects of the Single Point Mooring Buoy System, ASME.

Appendix C

FAILURE RATE DATA

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DEEPWATER PORT INSPECTION METHODS AND PROCEDURES.(U)
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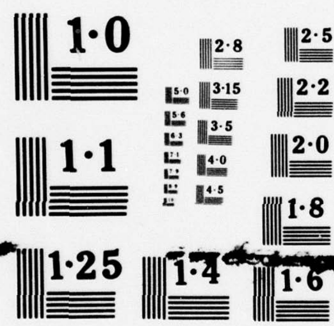
1·0
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Appendix C

FAILURE RATE DATA

This Appendix describes the failure rate data used in estimating the probability of oil spills from a DWP (Section 3.3). Reliability data for most of the elements of the OTS is scarce and no experiential data for a U.S. DWP exists, so data from other ports, other oil transfer systems, and, in some cases, other industries must be used in order to build an adequate data base. Subjective information, such as that derived from discussions with port operators and pipeline designers, was used along with the reliability data to incorporate U.S. operating philosophy wherever decisions were required. While this data base may not be directly related to DWP operations it is believed to reflect the best information available at this time.

The historical spill data from DWPs in other countries has been used to estimate the frequency and causes of spills for a U.S. DWP. These data (discussed in Section 3.1) represent the worldwide experiences of the late 1960s and early 1970s. Historical data indicates that there are 0.02 spills/ship call at SPMs. For all spills, 80% are caused by hose failures which yields a spill rate of 0.016/ship call, or 1×10^{-3}/hr*, for hose strings. (We assume that this rate applies to a string of two 1300' hoses.) Other spill causes and the rates with which they occur are**

- Swivel leaks — 4.9×10^{-5}/hr
- Expansion joint leaks, tankship — 4.9×10^{-5}/hr
- Mooring lines break — 4.9×10^{-5}/hr
- Hoses damaged — 0.0189/yr

Pipeline failure data, as reported by the Office of Pipeline Safety Operations, was used to estimate failure probabilities for the offshore and SPM pipelines. This data was drawn from a population of terrestrial

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*Assumes a 16-hour offloading period for each ship call.

**Estimated using the data in Table 3-5, the basic spill rate of 0.02 spills per ship call, and 16 hours offloading per ship call.

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pipelines for sizes greater than 12 inches, and only a part of it actually represents large (>30" OD) pipelines. Using all of the data as representative of large pipeline such as that used in a DWP requires that we assume that the failures are not a strong function of pipeline size. Also using mostly terrestrial pipeline data requires the assumption that the hazards to offshore and terrestrial pipelines are similar. Corrosion, structural, fabrication and installation failures are similar for both types. A common cause of failures in terrestrial pipelines is damage during nearby construction. This problem is similar in nature to a pipeline offshore being damaged by a ship's anchor, a trawler, or during construction of another pipeline. Moreover, as discussed in Section 3.2, available data indicate that the accident rate for the two types of pipe may be nearly the same. The failure probabilities derived from OPSO data are

Failure due to welds	3×10^{-8}/ft-yr
Failure due to corrosion	2×10^{-8}/ft-yr
Failure due to all causes	1×10^{-7}/ft-yr

This compares conservatively with the pipe failure probability quoted in the Reactor Safety Study (RSS). There, the value given is 3×10^{-8}/ft-yr for pipes with diameter >3".

The causes of hose failures have been extensively studied by Southwest Research Institute. Several potential causes were identified, however, historical data is not sufficiently detailed to determine the specific causes of most of the spills. Consequently, failures of all the components of hose strings have been combined, except for hose damage. Of all spills reported from SPMs, 80% are attributed to hose string failures. This yields a hose string failure rate of 0.016/ship call or 1×10^{-3}/hr of usage. This number is assumed to apply to a string of two 1300' hoses. The failure rate for each of the two underbuoy hoses of a CALM is calculated by

$$\frac{2 \times 150' \text{ (underbuoy hose length)}}{2 \times 1300' \text{ (floating hose length)}} \times \frac{1.0 \times 10^{-3}}{\text{hr}} = 1.2 \times 10^{-4}/\text{hr}$$

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The frequency of accidents which may cause sufficient damage to the pumping platform to cause a spill was estimated using data compiled by the U.S. Geological Survey about production platforms in the Gulf of Mexico. These data were discussed in Section 3.2. Reference 1 lists all occurrences of fires or explosions and all significant spill incidents according to platform, date, cause, volume of oil spilled, and consequences for 1960-1976. Prior to 1972, only incidents which resulted in spills of 50 barrels or more were reported in some categories, so a complete listing of events is not available for years earlier than 1972. Nevertheless, these data are helpful in estimating the probabilities of events for offshore platforms. The implicit assumption is made that the probability of fire, ship collision, and structural failure is the same for production platforms as for a DWP pumping platform.

Table C-1 lists the occurrences of fires or explosions which did result in an oil spill (all fires and explosions must be reported regardless of spill consequences).

Table C-1

PRODUCTION PLATFORM FIRES OR EXPLOSIONS
WHICH RESULTED IN AN OIL SPILL

Date	Event and Cause	Volume Spilled (bbl)
10/15/58	Explosion, fire-welding	Minimal
2/5/66	Fire-welding	Minimal
7/18/67	Explosion, fire-welding	Minimal
2/70	Fire	30,500
5/28/70	Explosion, fire-welding	100
8/23/72	Fire - engine	Minimal
7/1/74	Fire	1
8/10/75	Fire - leak	20

During the time period 1958 - 1976, there were 26,657 platform-years of exposure. Therefore, the probability of a fire which results in a spill was estimated by

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*Reference C-1 lists the number of offshore structures existing for each year 1964-1976. This list was extrapolated to obtain the number of structures for the years 1958-1963.

$$\frac{8\ \text{events}}{26{,}657\ \text{platform years}} = 3 \times 10^{-4}/\text{platform-year}$$

Three incidents have been reported for the years 1964-1976 in which a platform was struck by a ship and a spill resulted (greater than 50 bbl). These are listed in Table C-2.

Table C-2

SHIP COLLISIONS WITH PLATFORMS IN WHICH A SPILL RESULTED

Date	Volume Spilled (bbl)
4/8/64	2559
10/30/67	Minimal
5/21/74	100

One other event was recorded in which a spill resulted from a ship-platform collision; however, the oil leaked from the ship, not the platform. The number of platform-years during this period was 22,157.* The probability of a ship collision which results in a spill from the platform is estimated by

$$\frac{3\ \text{events}}{22{,}157\ \text{platform-years}} = 1.4 \times 10^{-4}/\text{platform-year}$$

Two incidents have occurred in which platforms were damaged or destroyed due to underwater structural failures during 1964-1976. The probability of structural failure of the platform is then

$$\frac{2\ \text{events}}{22{,}157\ \text{platform-years}} = 9.0 \times 10^{-5}/\text{platform-year}$$

During the time interval 1971-1975, 60 instances were reported in which the waste disposal systems on platforms caused spills. The number of platform years during this period was 9,960. This results in a

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*Reference C-1 lists the number of offshore structures existing for each year 1964-1976. This list was extrapolated to obtain the number of structures of the years 1958-1963.

probability of spill due to waste system overflow or carry over of

$$\frac{60 \text{ events}}{9{,}960 \text{ platform-years}} = 6.0 \times 10^{-3}\text{/platform-year}$$

Failure rates for components on the pumping platform were taken from other industries. Many came from the Reactor Safety Study (RSS) which reported failure rates for components found in nuclear power plants. This data was collected from many sources, including the Defense Department, general industrial sources, and nuclear power plant operating data. Use of these data for DWP components implies that similar maintenance and operating policies apply to both nuclear and DWP facilities. The failure rates used are listed in Table C-3. The units shown in the table are either $(\text{unit time})^{-1}$ or $(\text{demand})^{-1}$. The demand probabilities incorporate failure at demand, failure before demand, or failure to continue operation for a time sufficient to realize the required response.

Human reliability estimates were selected from the RSS and from research reports of Swain, Sandia Corporation (Reference C-2). The Sandia approach is to model the human activity for which estimates are desired as a composite of several basic tasks for which laboratory reliability estimates have been established. The combination of the basic task reliability estimates is the reliability estimate desired. The estimates obtained from this approach for tasks similar to those that will be performed on the pumping platform were reported in Reference C-3 and are shown in Table C-4.

Human failure rates for certain tasks were reported in the RSS. These were obtained by independent assessment of failure rates by two experts in human reliability analysis. The rates used in the RSS are presented in Table C-5. The impact of several performance shaping factors was considered in this study. These factors were:

1. Level of presumed psychological stress.
2. Quality of human engineering of controls and displays.
3. Quality of training and practice.
4. Presence and quality of written instructions a method of use.

Table C-3

COMPONENT FAILURE RATES

Component	Median Failure Rate	Comments
Pump-fails to start	1.0×10^{-3}/d	
Pump-mechnical seal leaks	6.0×10^{-6}/hr	
Gaskets-leak	3.0×10^{-6}/hr	
Flanges-leak	3.0×10^{-7}/hr	
Welds-leak	3.0×10^{-9}/hr	
Valves-MOV or check external leak or rupture	1.0×10^{-8}/hr	
Level Switch-fails to operate	3.0×10^{-4}/d	
Tank-rupture	3.0×10^{-9}/hr	Comparable to weld failure
Vane straightener-leak	3.0×10^{-9}/hr	Comparable to weld failure
Turbine meter-leak	3.0×10^{-9}/hr	Comparable to weld failure

Table C-4

HUMAN RELIABILITY ESTIMATE

TASK ELEMENT	RATING MEAN	RATING S.D.	RELIABILITY ESTIMATE
Read technical instructions	8.3	2.2	0.9918
Read time (Brush Recorder)	8.2	2.1	0.9921
Read electrical or flow meter	7.0	2.8	0.9945
Inspect for loose bolts and clamps	6.4	1.9	0.9955
Position multiple position electrical switch	6.3	2.4	0.9957
Mark position of component	6.2	2.1	0.9958
Install lockwire	6.0	2.3	0.9961
Inspect for bellows distortion	6.0	2.7	0.9961
Install Marman clamp	6.0	1.8	0.9961
Install gasket	6.0	2.1	0.9962
Inspect for rust and corrosion	5.9	2.1	0.9963
Install "O" ring	5.7	2.2	0.9965
Record reading	5.7	2.3	0.9966
Inspect for dents, cracks, and scratches	5.6	2.4	0.9967
Read pressure gauge	5.4	2.2	0.9969
Inspect for frayed shielding	5.4	2.3	0.9969
Inspect for QC seals	5.3	2.6	0.9970
Tighten nuts, bolts, and plugs	5.3	2.6	0.9970
Apply gasket cement	5.3	2.3	0.9971
Connect electrical cable (threaded)	5.2	2.2	0.9972
Inspect for air bubbles (leak check)	5.0	2.2	0.9974
Install reducing adapter	4.9	1.6	0.9975
Install initiator simulator	4.9	2.5	0.9975
Connect flexible hose	4.9	2.4	0.9975
Position "zero in" knob	4.8	1.6	0.9976
Lubricate bolt or plug	4.7	1.6	0.9979
Position hand valves	4.6	1.6	0.9979
Install nuts, plugs, and bolts	4.6	1.7	0.9979
Install union	4.5	1.8	0.9979
Lubricate "O" ring	4.5	2.5	0.9979
Rotate gearbox train	4.4	2.0	0.9980
Fill sump with oil	4.3	1.6	0.9981
Disconnect flexible hose	4.2	2.0	0.9982
Lubricate torque wrench adapter	4.2	2.2	0.9982
Remove initiator simulator	4.1	1.9	0.9983
Install protective cover (friction fit)	4.1	2.2	0.9983
Read time (watch)	4.1	2.1	0.9983
Verify switch position	4.1	1.9	0.9983
Inspect for lock wire	4.1	2.1	0.9983
Close hand valves	4.0	2.6	0.9983
Install drain tube	4.0	2.1	0.9983
Install torque wrench adapter	3.9	1.7	0.9984
Open hand valves	3.8	2.6	0.9985
Position two position electrical switch	3.8	1.5	0.9985
Spray leak detector	3.7	2.0	0.9986
Verify component removed or installed	3.5	2.4	0.9988
Remove nuts, plugs, and bolts	3.5	1.7	0.9988
Install pressure cap	3.4	1.6	0.9988
Remove protective closure (friction fit)	3.2	1.6	0.9990
Remove torque wrench adapter	3.0	1.6	0.9991
Remove reducing adapter	3.0	1.7	0.9991
Remove Marman clamp	3.0	1.7	0.9991
Remove pressure cap	2.8	1.8	0.9992
Loosen nuts, bolts, and plugs	2.8	1.3	0.9992
Remove union	2.7	1.4	0.9993
Remove lockwire	2.7	1.5	0.9993
Remove drain tube	2.6	1.4	0.9993
Verify light illuminated or extinguished	2.2	1.6	0.9996
Install funnel or hose in can	2.0	0.8	0.9997
Remove funnel from oil can	1.9	1.4	0.9997

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Table C-5

HUMAN ERROR RATES ESTIMATED

Estimated Rates	Activity
10^{-4}	Selection to a key-operated switch rather than a non-key switch (this value does not include the error of decision where the operator misinterprets situation and believes key switch is correct choice).
10^{-3}	Selection of a switch (or pair of switches) dissimilar in shape or location to the desired switch (or pair of switches), assuming no decision error. For example, operator actuates large handled switch rather than small switch.
3×10^{-3}	General human error of commission; e.g., misreading label and therefore selecting wrong switch.
10^{-2}	General human error of omission where there is no display in the control room of the status of the item omitted; e.g., failure to return manually operated test valve to proper configuration after maintenance.
3×10^{-3}	Errors of omission, where the items being omitted are embedded in a procedure rather than at the end as above.
3×10^{-2}	Simple arithmetic errors with self-checking but without repeating the calculation by re-doing it on another piece of paper.
1/x	Given that an operator is reaching for an incorrect switch (or pair of switches), he selects a particular similar appearing switch (or pair of switches), where x - the number of incorrect switches (or pair of switches) adjacent to the desired switch (or pair of switches). The 1/x applies up to 5 or 6 items. After that point the error rate would be lower because the operator would take more time to search. With up to 5 or 6 items he doesn't expect to be wrong and therefore is more likely to do less deliberate searching.
10^{-1}	Given that an operator is reaching for a wrong motor operated valve MOV switch (or pair of switches), he fails to note from the indicator lamps that the MOV(s) is (are) already in the desired state and merely changes the status of the MOV(s) without recognizing he had selected the wrong switch(es).

Table C-5 (continued)

Estimated Rates	Activity
~ 1.0	Same as above, except that the state(s) of the incorrect switch(es) is (are) not the desired state.
~ 1.0	If an operator fails to operate correctly one of two closely coupled valves or switches in a procedural step, he also fails to correctly operate the other valve.
10^{-1}	Monitor or inspector fails to recognize initial error by operator. Note: With continuing feedback of the error on the annunciator panel, this high error rate would not apply.
10^{-1}	Personnel on different work shift fail to check condition of hardware unless required by checklist or written directive.
5×10^{-1}	Monitor fails to detect undesired position of valves, etc., during general walk-around inspections, assuming no checklist is used.
.2 - .3	General error rate given very high stress levels where dangerous activities are occurring rapidly.
$2^{(n-1)}x$	Given severe time stress, as in trying to compensate for an error made in an emergency situation, the initial error rate, x, for an activity doubles for each attempt, n, after a previous incorrect attempt, until the limiting condition of an error rate of 1.0 is reached or until time runs out. This limiting condition corresponds to an individual's becoming completely disorganized or ineffective.
~ 1.0	Operator fails to act correctly in the first 60 seconds after the onset of an extremely high stress condition; e.g., a large LOCA.
9×10^{-1}	Operator fails to act correctly after the first 5 minutes after the onset of an extremely high stress condition.
10^{-1}	Operator fails to act correctly after the first 30 minutes in an extreme stress condition.

Table C-5 (continued)

Estimated Rates	Activity
10^{-2}	Operator fails to act correctly after the first several hours in a high stress condition.
x	After 7 days after a large LOCA, there is a complete recovery to the normal error rate, x, for any task.

(a) Modification of these underlying (basic) probabilities were made on the basis of individual factors pertaining to the tasks evaluated.

(b) Unless otherwise indicated, estimates of error rates assume no undue time pressures or stresses related to accidents.

5. Coupling of human actions.
6. Type of display feedback.
7. Personnel redundancy.

Of particular interest is their conclusions that, the minimum error rate for human performance of a task was 10^{-5}/task. Even in situations where the performance and verification of the task was completed independently, this minimum rate was assumed. This conclusion was based on the difficulties and subjective nature of estimating human reliability. The same minimum human error rate of 10^{-5}/d will be assumed in this analysis to ensure conservative estimates.

The human failure rates used in this analysis are presented in Table C-6.

Table C-6
HUMAN ERROR RATES

Activity	Error Rate
Verify Switch Position	2×10^{-3}/D
Verify Component Installed/Removed	1.2×10^{-3}/D
Close Hand Valve	1.7×10^{-3}/D
Complete Procedure	3×10^{-3}/D
Perform and Verify Task	1×10^{-5}/D

Table C-7 (Table 3-12 in main text) presents all of the failure rates used in this analysis. To accurately determine the probability of oil spill from a DWP, not only single-point estimates of failure rates must be known, but also the statistical distribution of the failures should be used to determine the sensitivity of the prediction to perturbations in the failure rates. The RSS quotes error factors for component failures and assumes a lognormal distribution for all failures so that sensitivity can be examined. (These assumptions are currently being reviewed for validity.) In this analysis, however, this phase of data collection was hampered by the scarcity of data. Therefore, no estimate of the distribution of spill frequency as a function of failure rate distributions is provided.

Rates for other failures which appear on the fault trees (Section 3.3) were calculated as needed. These include:

1. Spill Tank Overflows = Pr (Large Valve Leak) x Pr (Tank not Checked Hourly) = $\frac{4 \times 10^{-11}}{hr} \times \frac{3 \times 10^{-3}}{d} \times 1.2 \times 10^{-13}$/hr.
2. Hose Fracture During Breakout = 1.
3. Insufficient Time to Disconnect Hoses During Breakout = 1
4. Earthquake Damages Platform $<10^{-6}$/yr for Locations in the Gulf of Mexico. For West Coast locations the probability is 10^{-5}/yr (C-4).
5. Vane straightener and turbine flow meter leaks   weld leaks.
6. Hole in Deck = Pr (Repair Not Completed/Hole) x Pr (Inspection Not Completed/Hole) x Pr(Hole) = $3.7 \times 10^{-3} \times 1.7 \times 10^{-3}$ x 1 10^{-5}/yr.
7. Pump Mechanical Seal Leaks = 2 x Pr(Gasket Leaks) = $2 \times 3 \times 10^{-6}$/hr = 6×10^{-6}/hr.

Table C-7

FAILURE RATE DATA

Component Failure/ Event Activity	Failure Rate	Data Source
Pump-fails to start	1×10^{-3} /D	RSS
Level Switch-fails to operate	3×10^{-4}/D	RSS
Flange - leak	3×10^{-7}/hr	RSS
Gasket - leak	3×10^{-6}/hr	RSS
Weld - leak	3×10^{-9}/hr	RSS
Valves-MOV or Check external leak or rupture	1×10^{-8}/hr	RSS
Pipe-leaks, all causes	1×10^{-7}/ft-yr 1×10^{-11}/ft-hr	OPS
Pipe-weld leaks	3×10^{-8}/ft-yr	OPS
Pipe-corrosion failure	2×10^{-8}/ft-yr	OPS
Hose-leak from string	1×10^{-3}/hr	OE
Hose-external damage	2.2×10^{-6}/hr	OE
Mooring-lines break	4.9×10^{-5}/hr	OE
Ship expansion joint - leaks	4.9×10^{-5}/hr	OE
Fluid Swivel-leaks	4.9×10^{-5}/hr	OE
Operator-verify switch position	2×10^{-3}/D	Sandia
Operator-verify component installed/ removed	1.2×10^{-3}/D	Sandia
Operator-close hand valve	1.7×10^{-3}/D	Sandia
Operator-complete procedure	3×10^{-3}/D	Sandia
Ship Collision-spill	1.4×10^{-4}/yr	USGS
Fire or explosion-spill	3×10^{-4}/yr	USGS

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Table C-7 (continued)

Component Failure/ Event Activity	Failure Rate	Data Source
Platform supports-structural failure	9×10^{-5}/yr	USGS
Waste System - spill	6.0×10^{-3}/yr	USGS
Pump-mechanical seal leaks	6×10^{-6}/hr	2
Underbuoy Hose-leaks	1.2×10^{-4}/hr	2
Vane Straightener - leaks	3×10^{-9}/hr	2
Turbine Flow Meter - leaks	3×10^{-9}/hr	2
Deck - hole not repaired	1×10^{-5}/yr	2
Hose - filled with oil between ships	0.6 /yr	2
Earthquake	$<10^{-6}$/yr	2

1. Operating Experience (OE)

2. Calculated using the assumption stated in the text of Appendix C.

Appendix C

REFERENCES

C-1. "Accidents Connected with Federal Oil & Gas Operation on the Outer Continental Shelf," USGS Conservation Division, January 1977.

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